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National Energy Board

Reasons for Decision

CanWest Gas Supply Inc.

Enserch Development Corporation, on behalf of Encogen Northwest, L.P.

Kamine Natural Dam Cogen Co., Inc.

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & ATCOR Ltd.

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New York State Electric & Gas Corporation

GH-1-92

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October 1992

Volume II

Gas Exports

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National Energy Board

Reasons for Decision

IN THE MATTER OF

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New York State Electric & Gas Corporation

Petro-Canada

TransCanada PipeLines Limited

Applications Pursuant to Part VI of the *National Energy Board Act* for Licences to Export Natural Gas and,

Esso Resources Canada Limited/Esso Resources Canada/
Transco Energy Marketing Company/CanStates Gas Marketing

Application Pursuant to Part I of the *National Energy Board Act* for the Transfer of a Licence to Export Natural Gas

GH-1-92

October 1992

Volume II
Gas Exports

© Minister of Supply and Services Canada 1992

Cat. No. NE22-1/1992-7-2E
ISBN 0-662-20057-8

This report is published separately in both official languages

Copies are available on request from:

Regulatory Support Office
National Energy Board
311 - 6th Avenue S.W.
Calgary, Canada
T2P 3H2
(403) 292-4800

Printed in Canada

Ce rapport est publié séparément dans les deux langues officielles

Exemplaires disponibles auprés du:

Bureau du soutien de la réglementation
Office national de l'énergie
311, 6e avenue s.-o.
Calgary (Canada)
T2P 3H2
(403) 292-4800

Imprimé au Canada

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder;

AND IN THE MATTER OF applications under Part VI of the *National Energy Board Act* for new licences to export natural gas by:

AG-Energy, L.P.; Canadian Hydrocarbons Marketing Inc.; Canadian-Montana Pipe Line Company; CanWest Gas Supply Inc.; Enserch Development Corporation, on behalf of Encogen Northwest, L.P.; Husky Oil Operations Ltd.; Kamine Natural Dam Cogen Co., Inc.; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & ATCOR Ltd.; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & Esso Resources Canada; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited; New York State Electric & Gas Corporation; Petro-Canada; and TransCanada PipeLines Limited

AND IN THE MATTER OF an application under Part I of the *National Energy Board Act* for the transfer of a licence to export natural gas by:

Esso Resources Canada Limited / Esso Resources Canada / Transco Energy Marketing Company / CanStates Gas Marketing

AND IN THE MATTER OF Hearing Order GH-1-92, as amended;

HEARD in Calgary, Alberta on 21, 22 and 23rd April 1992.

BEFORE:

A.B. Gilmour	Presiding Member
R.B. Horner, Q.C.	Member
R.L. Andrew, Q.C.	Member

APPEARANCES:

A.S. Hollingworth C.I. MacLean	AG-Energy, L.P.
P. J. McIntyre R.B. Brander	Canadian Hydrocarbons Marketing Inc.
A.R. O'Brien	Canadian-Montana Pipe Line Company
L.E. Smith N.M. Gretener	CanWest Gas Supply Inc.; and New York State Electric & Gas Corporation
D.W. Rowbotham	Enserch Development Corporation, on behalf of Encogen Northwest, L.P.
T.M. Hughes	Esso Resources Canada Limited / Esso Resources Canada / Transco Energy Marketing Company / CanStates Gas Marketing

S. Carscallen	CanStates Gas Marketing
J. Ebert	Transco Energy Marketing Company
D.A. Holgate	Husky Oil Operations Ltd.; and Kamine Natural Dam Cogen Co., Inc.
S.R. Miller	Petro-Canada
L.G. Keough	Makowski Selkirk, Inc. on behalf of: Selkirk Cogen Partners II, L.P. & ATCOR Ltd.; Selkirk Cogen Partners II, L.P. & Esso Resources Canada; and Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited
E.P. Varga	TransCanada PipeLines Limited
H.T. Soudek	The Consumers' Gas Company Ltd.; and St. Lawrence Gas Company, Inc.
R.R. Argamany	Mobil Oil Canada
K.L. Meyer	Pan-Alberta Gas Ltd.
R.B. Hillary	Paramount Resources Ltd.
J. Kowch	ProGas Limited
E.B. McDougall	Washington Natural Gas Company
G. Britton	Western Gas Marketing Limited
J. Syme P. Noonan	National Energy Board

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Abbreviations

Act	*National Energy Board Act*
AG-Energy	AG-Energy, L.P.
APMC	Alberta Petroleum Marketing Commission
ATCOR	ATCOR Ltd.
Bcf	billion cubic feet
BCPC	British Columbia Petroleum Corporation
Board	National Energy Board
by-pass	the total avoidance of an LDC's system for the transportation of gas
CanWest	CanWest Gas Supply Inc.
Cascade	Cascade Natural Gas Corporation
CHMI	Canadian Hydrocarbons Marketing Inc.
CMPL	Canadian-Montana Pipe Line Company
Con Ed	Consolidated Edison of New York, Inc.
Contract Price volumes	In the gas contract between Selkirk and PanCanadian, volumes of gas that Selkirk may purchase, up to the MDQ, at the prevailing commodity charge
CSGM	CanStates Gas Marketing
DA	Development Associates Inc.
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
EIA	Export Impact Assessment
EMA	Energy Management Associates, Inc.
EMPR	(British Columbia) Ministry of Energy, Mines and Petroleum Resources

Encogen	Encogen Northwest, L.P.
ERC	Esso Resources Canada
ERCB	(Alberta) Energy Resources Conservation Board
ERCL	Esso Resources Canada Limited
FERC	(United States of America) Federal Energy Regulatory Commission
FS	Firm Service
GE	General Electric Company, Plastics Division
Georgia-Pacific	Georgia-Pacific Corporation
GIC	gas inventory charge
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Limited Partnership
Husky	Husky Oil Operations Ltd.
Hydro-Québec decision	*Attorney General of Québec* v. *National Energy Board* (1991), 132 N.R. 214 (F.C.A.)
IDV	Incremental Daily Volume
IGTS	Iroquois Gas Transmission System, L.P.
James River	James River Paper Company, Inc. or the James River Paper Company, Inc. paper mill located in Natural Dam, New York
Joint Applicants	ERCL, ERC, TEMCO and CSGM
Kamine	Kamine Natural Dam Cogen Co., Inc.
MAQ	Minimum Annual Quantity
MDQ	Maximum Daily Quantity
MMBtu	million British thermal units
MMcf	million cubic feet
MPC	The Montana Power Company

NCM	North Canadian Marketing Inc.
NCO	North Canadian Oils Limited
NEB	National Energy Board
Negotiated Price volumes	In the gas contract between Selkirk and PanCanadian, volumes of gas that Selkirk may purchase at negotiated prices reflecting spot market conditions
Niagara	Niagara Mohawk Power Corporation
North Country	North Country Gas Pipeline Corporation
Northwest	Northwest Pipeline Corporation
Northwest Natural	Northwest Natural Gas Company
NOVA	NOVA Corporation of Alberta
NYPP	New York Power Pool
NYPSC	New York Public Service Commission
NYSEG	New York State Electric and Gas Corporation
PanCanadian	PanCanadian Petroleum Limited
Part VI Regulations	*National Energy Board Part VI Regulations*
ProGas	ProGas Limited
Puget	Puget Sound Power & Light Company
PURPA	(United States of America) Public Utility Regulatory Policies Act
QF	qualifying cogeneration facility
Selkirk	Makowski Selkirk, Inc. or Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P.
Selkirk I	Phase I of the cogeneration facility to be constructed by Makowski Selkirk, Inc. (Heard in GH-5-89)
Selkirk II	Phase II of the cogeneration facility to be constructed by Makowski Selkirk, Inc. (The subject of the present application)
St. Lawrence Gas	St. Lawrence Gas Company, Inc.

TEMCO	Transco Energy Marketing Company
Tenaska	Tenaska Gas Co.
Tennessee	Tennessee Gas Pipeline Company
Tier 1 volumes	Volumes up to the Minimum Annual Quantity in the gas sales contracts between Selkirk and each of ATCOR and ERC. The commodity charge for Tier 1 volumes differs between the contracts.
Tier 2 volumes	Volumes in excess of the Minimum Annual Quantity in the gas sales contracts between Selkirk and each of ATCOR and ERC. The commodity charge for Tier 2 volumes differs between the contracts.
TransCanada	TransCanada PipeLines Limited
TransGas	TransGas Limited
U.S.	United States of America
Westcoast	Westcoast Energy Inc.
WNG	Washington Natural Gas Company
WUTC	Washington Utilities and Transportation Commission

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-1-92 proceeding, the National Energy Board ("the Board") examined 13 applications for gas export licences and one application for the transfer of a gas export licence. The applications were filed by the following companies:

1. AG-Energy, L.P. ("AG-Energy");

2. Canadian Hydrocarbons Marketing Inc. ("CHMI");

3. Canadian-Montana Pipe Line Company ("CMPL");

4. CanWest Gas Supply Inc. ("CanWest");

5. Enserch Development Corporation, on behalf of Encogen Northwest, L.P. ("Encogen");

6. Esso Resources Canada Limited ("ERCL") / Esso Resources Canada ("ERC") / Transco Energy Marketing Company ("TEMCO") / CanStates Gas Marketing ("CSGM") (collectively called "the Joint Applicants") for the transfer of Licence GL-136;

7. Husky Oil Operations Ltd. ("Husky");

8. Kamine Natural Dam Cogen Co., Inc. ("Kamine");

9. Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. ("Selkirk") and ATCOR Ltd. ("ATCOR");[1]

10. Selkirk and ERC;[2]

11. Selkirk and PanCanadian Petroleum Limited ("PanCanadian");

12. New York State Electric & Gas Corporation ("NYSEG");

13. Petro-Canada; and

14. TransCanada PipeLines Limited ("TransCanada").

---

1. During the Hearing, Selkirk requested that its applications be amended so that any licences granted be issued in the name, in part, of Selkirk Cogen Partners, L.P. instead of in the name, in part, of Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P.

2. By letter dated 9 June 1992, Selkirk and ERC requested that their application be amended so that any licence granted be issued in the name, in part, of Imperial Oil Resources, instead of in the name, in part, of Esso Resources Canada.

Table 1-1 provides a summary of each export licence application reviewed during the GH-1-92 proceeding.

The Joint Applicants, ERC/ERCL/TEMCO/CSGM, requested that the Board issue its decision at as early a date as possible. The Joint Applicants made this request due to certain contractual provisions that required Governor in Council approval of the transfer of Licence GL-136 prior to 1 September 1992. Consequently, the Board decided to publish its GH-1-92 Reasons for Decision in two volumes. The Board issued Volume I of its GH-1-92 Reasons for Decision in August 1992. Volume I dealt with the applications by AG-Energy, CHMI, CMPL, the Joint Applicants, Husky, Petro-Canada and TransCanada.

The applications by CanWest, Encogen, Kamine, Selkirk and ATCOR, Selkirk and ERC, Selkirk and PanCanadian, and NYSEG are dealt with in this Volume II.

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the *National Energy Board Act* ("the Act"), which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The following discussion of the Board's Market-Based Procedure is general in nature and applies to each application heard in the GH-1-92 proceeding.

The Market-Based Procedure provides that the Board consider:

- complaints, if any, under the Complaints Procedure;
- an Export Impact Assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

In GHW-1-91, the Board advised interested parties of proposed changes to be made to the Market-Based Procedure. These proposed changes affect the application of the Complaints Procedure and the other public interest considerations. Comments from parties were requested to be filed on 15 October 1991 with reply comment by 20 December 1991.

As the GHW-1-91 proceeding was not completed at the time the Board examined the 14 applications heard in GH-1-92, the Board relied upon the existing procedure for its assessment of the applications.

1.2.1 Complaints Procedure

When an application for an export licence is filed with the Board, interested parties have an opportunity to examine the various elements of the proposal. It is open to Canadian users of natural gas to come forward and object to the export on the ground that they cannot obtain additional supplies of gas on terms and conditions, including price, similar to those in the export proposal.

Table 1-1

Summary of Applied-for Licences

GH-1-92

Application	Buyer (Type of market)	Term	Export Point	Maximum Quantities Applied For: Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1. AG-Energy	AG-Energy (cogen. plant)	1 Sept. 1993 to 31 Oct. 2008	Iroquois, Ontario	467.0 (16.5)	170.6 (6.0)	2 587.0 (91.3)
2. CHMI	WNG (system supply)	1 Nov. 1992 to 31 Oct. 2002	Huntingdon, British Columbia	273.9 (9.7)	100.0 (3.5)	1 000.3 (35.3)
3. CMPL	MPC (system supply)	1 Nov. 1992 to 31 Oct. 2006	Aden, Alberta	1 416.4 (50.0)	283.3 (10.0)	3 966.2 (140.0)
4. CanWest	Northwest (system supply)	for 12 years following 1st del.	Huntingdon, British Columbia	2 606.0 (92.0)	952.0 (34.0)	11 415.0 (403.0)
5. Encogen	Encogen (cogen. plant)	1 April 1993 to 31 March 2008	Huntingdon, British Columbia	271.8 (9.6)	99.1 (3.5)	1 441.3 (50.9)
6. ERC/ERCL/ TEMCO/CSGM	TEMCO (system supply)	1 Nov. 1990 to 31 Oct. 2002	Niagara Falls, Ontario	2 125.0 (75.0)	775.6 (27.4)	9 307.5 (328.6)
7. Husky	Tenaska (cogen. plant)	for 17.25 years following 1st del.	Huntingdon, British Columbia	366.2 (13.0)	133.7 (4.8)	2 306.6 (81.9)
8. Kamine	Kamine (cogen. plant)	1 Nov. 1993 to 31 Oct. 2008	Iroquois, Ontario	339.8 (12.0)	117.8 (4.2)	1 767.1 (62.4)
9. Selkirk & ATCOR	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	479.0 (17.0)	176.1 (6.2)	2 712.0 (95.8)
10. Selkirk & ERC	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	538.2 (19.0)	196.6 (6.9)	3 031.0 (107.0)
11. Selkirk & PanCanadian	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	538.2 (19.0)	196.6 (6.9)	3 031.0 (107.0)
12. NYSEG	NYSEG (system supply)	for 12 years following 1st del.	Napierville, Québec	255.0 (9.0)	93.1 (3.3)	1 117.0 (39.6)
13. Petro-Canada	Tenaska (cogen. plant)	for 17.25 years following 1st del.	Huntingdon, British Columbia	409.6 (14.1)	150.0 (5.1)	2 580.9 (91.1)
14. TransCanada	GLGT (fuel gas)	1 Feb. 1992 to 31 Oct. 2005	Emerson, Manitoba	2 785.0 (98.4)	875.0 (30.9)	12 035.0 (424.9)

There were no complaints made with respect to the applications for export licences in the GH-1-92 proceeding.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.

In a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non-project-specific assessment. Each applicant now has the option of using the Board's most recent analysis or of preparing and submitting its own analysis as a basis for assessing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

The seven applicants included in this volume adopted the Board's EIA.

In this regard, the Board believes that the applied-for export volumes would have little impact on the production, consumption and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed exports. The Board is also of the view that Canadian buyers of natural gas would not have significant problems adjusting to market forces that would result from approval of these exports.

1.2.3 Other Factors Relevant to the Public Interest

In addition to using the Complaints Procedure and the EIA to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest.

In general, these factors can be placed into two categories: (a) gas supply and (b) market, commercial arrangements and regulatory status. This listing of factors that the Board may regard as relevant is illustrative rather than exhaustive, but the Board relies heavily on information filed by export licence applicants in accordance with the *National Energy Board Part VI Regulations* ("Part VI Regulations"). This information is used to assess whether an export proposal is in the public interest. The onus is on each applicant to ensure that the filed material is such as to persuade the Board that the project has substance and is at a sufficiently advanced stage of completion to warrant the issuance of a licence.

1.2.3.1 Gas Supply

The Board conducts a review of each applicant's gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply, the adequacy of both reserves and productive capacity to support the applied-for export and the status of provincial removal authorizations.

Each applicant provides an estimate of remaining established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducts geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's marketable gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and an assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board's estimate of reserves, along with basic deliverability data for each pool for which estimates of reserves were submitted, are used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are based on a load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements. To the extent that a lower load factor was anticipated, productive capacity would be sustained beyond the time the Board's analysis indicates.

1.2.3.2 Market, Commercial Arrangements and Regulatory Status

The Board conducts a review of the market, commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest. The applications dealt with in GH-1-92 were for sales to two types of end-use markets: sales for system supply and sales to cogeneration facilities. The Board's review of these market types included consideration of the following for each market type:

- for exports for system supply, it included consideration of the purchaser's current and projected requirements and supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio; and,

- for exports to a cogeneration facility, defined as a facility that produces electricity and thermal energy for use in commercial or industrial operations, an examination of the contractual chain, from the gas contract to the power and thermal sales contracts, was conducted. In this regard the Board looked to the status of project financing, construction schedules and qualifying cogeneration facility ("QF") certification under the Public Utility Regulatory Policies Act ("PURPA") of the United States of America ("U.S.").

For each type of end-use market, the review included consideration, among other items, of the load factors at which the proposed exports are expected to flow and the status of pertinent regulatory authorizations in Canada and the U.S.

The Board's review of the commercial arrangements included consideration of information each applicant was required to file in accordance with the Part VI Regulations and in response to Board information requests issued during the hearing. This information included the following:

- the status of upstream and downstream transportation arrangements, including all transportation contracts, either in final form or as precedent agreements;

- the contractual obligations between the Canadian sellers and the U.S. buyers, including executed gas sales contracts;
- any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including filing of these downstream contracts; and
- for cogeneration facilities, the contractual obligations between the cogeneration facility and the electric utility and the steam host.

In its review of the gas sales contracts between the Canadian sellers and the U.S. buyers, the Board made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;
- whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;
- whether the contracts ensure that the volumes contracted for are likely to be taken; and
- whether the contracts have the support of the Canadian producer(s) supplying the gas to the export project.

With respect to the second of the factors listed above, that of contractual responsiveness to changing market conditions, the Board recognizes that there may be cases where contracts are attractive to the parties involved, notwithstanding a lack of flexibility. In implementing the criterion relating to contract responsiveness, the Board operates on the presumption that, where contracts are freely negotiated at arm's length, they are in the public as well as private interest.

1.3 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

1.4 Environmental Screening

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* ("the EARP Guidelines Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Guidelines Order, the Board would be instituting a screening procedure to examine the potential environmental effects of each export proposal before the Board.

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the EARP Guidelines Order. To that end, the Board performed a screening, pursuant to Hearing Order GH-1-92, as amended, wherein it considered submissions from each applicant and from interested parties to GH-1-92.

On 9 July 1991, the Federal Court of Appeal issued its decision in the case of *Attorney General of Québec* v. *National Energy Board* (1991), 132 N.R. 214 (F.C.A.) ("the Hydro-Québec decision"). The Court held that the Board's jurisdiction over exports (in this case, electricity exports) did not extend to the facilities used for the production of the good for export. Accordingly, as was stated by Mr. Justice Marceau, speaking on behalf of the Court (at page 6):[1]

> " The factors which may be relevant in considering an application for leave to export electricity and the conditions which the Board may place on its leave clearly cannot relate to anything but the export of electricity".

The Board is of the view that the Hydro-Québec decision applies to the regulation of gas exports as well as electricity exports.

Each applicant filed with the Board information concerning the potential environmental effects and the social effects directly related to those environmental effects that would be caused by the moving of gas from Canada. All interested parties were served with these written submissions.

Mr. R.E. Wolf provided public interest evidence in regard to each of the applications. Mr. Wolf expressed concern that biodiversity was being destroyed as a result of seismic exploration, access road, well site and pipeline right-of-way development without considering the environmental consequences of such actions. Mr. Wolf stated that wildlife resources and habitat need to be protected and was also concerned that low natural gas prices would prevent producers from properly restoring drill sites and from protecting ground water, which could be contaminated by the contents of the drilling sumps.

In his letter of comment filed in the proceeding, Dr. Brian Horejsi, representing the Speak Up For Wildlife Foundation, objected to the granting of gas export licences until the upstream effects on biodiversity, ecosystem viability and sustainability, and wildlife conservation are addressed in a comprehensive and public environmental assessment process. Dr. Horejsi wrote that this process must be based on an independently controlled environmental impact statement that considers:

(a) the various regions from which gas is extracted for export;
(b) the cumulative effects of energy developments and other kinds of developments; and
(c) an ecosystem approach to assessment.

As well, the environmental impact statement should be subject to a full, public review through a clearly defined, written administrative and/or legislated process.

NYSEG and CanWest submitted that concerns relating to upstream environmental matters, which appeared to be the focus of Mr. Wolf's and Dr. Horejsi's objections, are matters outside of the Board's jurisdiction and are more correctly dealt with by the individual provincial regulators. NYSEG and CanWest further submitted that the environmental effects of facilities which are

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1. On 11 June 1992, Leave to Appeal the Hydro-Québec decision was granted to the Grand Council of the Crees of Québec by the Supreme Court of Canada.

required to transport the gas are properly and correctly dealt with by the Board in comprehensive Part III, not Part VI, proceedings.

The Board, by means of a screening pursuant to the EARP Guidelines Order, has concluded that the applications of CanWest, Encogen and NYSEG fall within the ambit of Note 3 of the Board's EARP Guidelines Order Automatic Exclusion List and therefore require no further examination. For the remaining applications, the Board has completed its environmental screening and has concluded that the potentially adverse environmental effects and the social effects directly related thereto are insignificant or mitigable with known technology.

The Board acknowledged Mr. Wolf's and Dr. Horejsi's concerns regarding the effects of natural gas development upon the environment and the wildlife. However, environmental matters associated with the drilling and development of natural gas resources within a province are outside the Board's jurisdiction. Such concerns are correctly dealt with by provincial regulators within their legislative mandate.

Chapter 2

CanWest Gas Supply Inc.

2.1 Application Summary

By application dated 12 November 1991, CanWest sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	For a period of 12 years following the first day of the first month following first deliveries.	
Point of Export	-	near Huntingdon, British Columbia	
Maximum Daily Quantity	-	2 606 10^3m^3	(92 MMcf)
Maximum Annual Quantity	-	952 10^6m^3	(34 Bcf)
Maximum Term Quantity	-	11 415 10^6m^3	(403 Bcf)
Tolerance	-	10 percent per day and 2 percent per year	

The gas destined for export would be produced from pools contracted to CanWest in British Columbia. The gas would be transported on the Westcoast Energy Inc. ("Westcoast") system for delivery at the international border near Huntingdon, British Columbia to Northwest Natural Gas Company ("Northwest Natural"). The gas would then be shipped on the Northwest Pipeline Corporation ("Northwest") system to serve Northwest Natural's market.

2.2 Gas Supply

2.2.1 Supply Contracts

CanWest will provide the gas for the export from its contracted supply pool. This supply pool consists of dedicated, reserve-based gas purchase contracts with about 155 producers. Most of these contracts provide for a rate-of-take of 1:3650 over a ten-year term, although some of CanWest's older contracts have terms of 15 to 20 years with a rate-of-take of 1:5750.

2.2.2 Reserves

Table 2-1 shows that the Board's estimate of CanWest's contracted remaining marketable gas reserves is three percent lower than CanWest's estimate. The Board's estimate of CanWest's total gas supply exceeds the total requirements including the proposed export volumes by 38 percent.

In its analysis of CanWest's gas supply, the Board recognized 284 pools located throughout northeastern British Columbia. Eighteen pools with initial marketable reserves larger than 3 000 10^6m^3 (106 Bcf) represent 64 percent of the total reserves. One of these pools, the Yoyo

Table 2-1

Comparison of Estimates of CanWest's Established Gas Reserves With the Applied-for Term Volume

10^6m^3 (Bcf)

CanWest[1]	NEB[2]	Applied-for[3] Volume
67 049 (2 368)	65 179 (2 302)	11 415 (403)

1. As of 1 November 1991.
2. As of 31 December 1990. The Board's estimate of remaining reserves would be about 3 700 10^6m^3 (131 Bcf) less than shown if further adjusted for CanWest's first 10 months of 1991 production. The Board's estimate would be eight percent less than CanWest's estimate but 30 percent greater than CanWest's total requirements.
3. This represents about 24 percent of CanWest's total requirements, which are 47 307 10^6m^3 (1,671 Bcf).

Pine Point A pool has net remaining reserves of 9 390 10^6m^3 (332 Bcf) or fourteen percent of CanWest's total remaining reserves.

Ninety-two percent of CanWest's pools are on production, with the eighteen largest pools having produced for more than 15 years. Sproule Associates Limited, an independent consultant, prepared the estimate of reserves submitted by CanWest. Considering the maturity of many of the pools, the principal techniques used by both the Board and Sproule Associates Limited to determine reserves were production decline analysis and material balance (P/Z plots) analysis.

In summary, the Board's estimate of reserves is similar to CanWest's and both estimates exceed the applied-for volume. Small variances in reservoir parameters and in the interpretation of production declines and material balance account for the minor difference in the estimates of reserves.

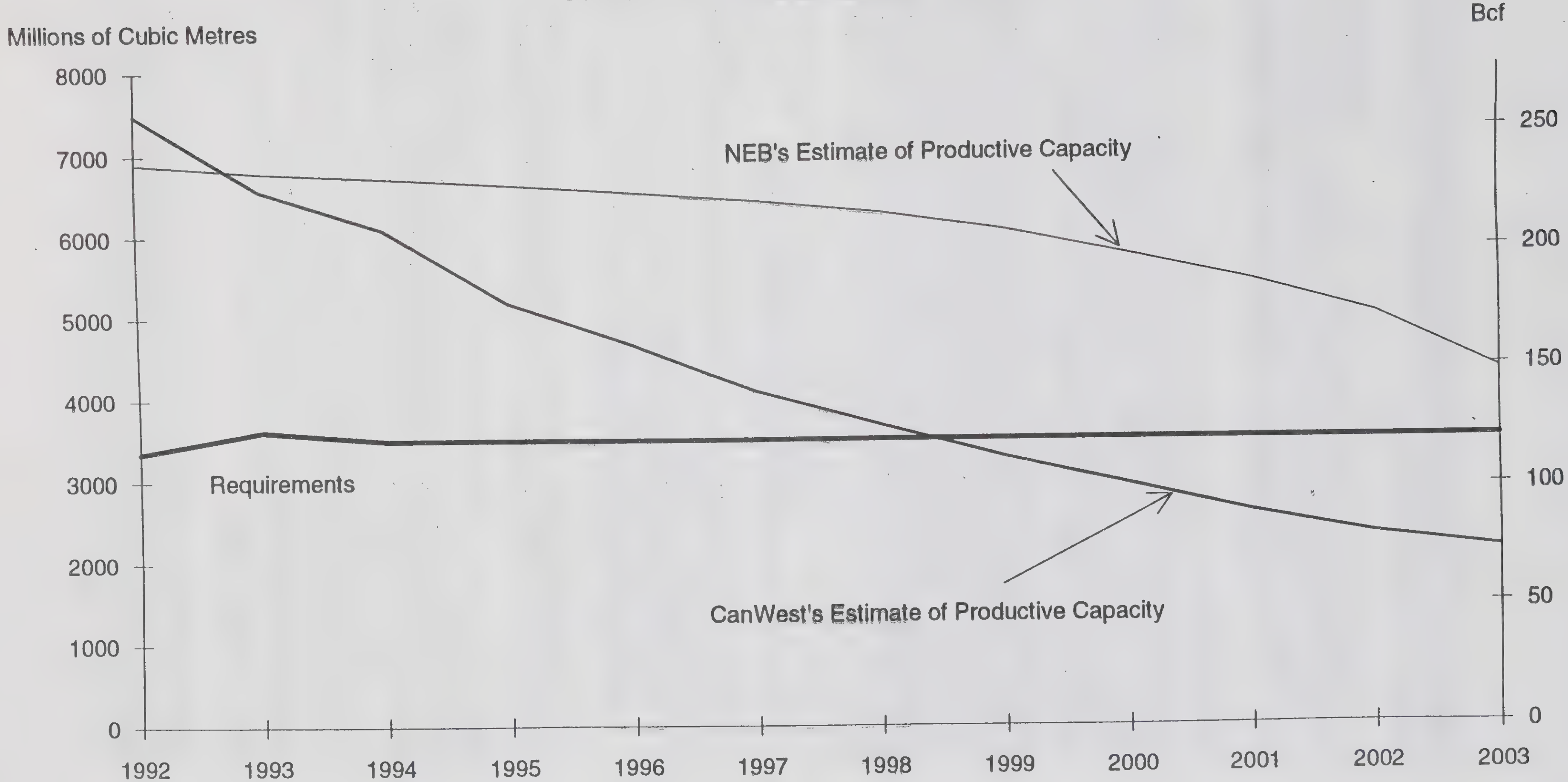
2.2.3 Productive Capacity

Figure 2-1 compares the Board's and CanWest's projections of productive capacity with CanWest's total requirements. CanWest's total requirements include the proposed exports to Northwest Natural and Encogen. The latter application is discussed in Chapter 3 of these Reasons.

The Board's projection of productive capacity, which was adjusted to reflect production at the level of requirements shown in Figure 2-1, indicates adequate gas supply throughout the proposed

Figure 2-1

COMPARISON OF CANWEST'S AND NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



export term. CanWest's projection, which assumes annual production of all available supply, shows adequate gas supply until 1999. With this assumption, CanWest suggested that its projection is a conservative outlook.

CanWest stated that any shortfalls in gas supply could be remedied by increasing the rate-of-take for some of its contracts with other producers or by purchasing additional reserves.

2.3 Market, Commercial Arrangements and Regulatory Status

2.3.1 Market

Northwest Natural is a local distribution company serving customers in northwest Oregon and southwest Washington. The company is presently supplying gas to 320,000 customers and has annual gas sales exceeding 2 832 10^6m^3 (100 Bcf). Northwest Natural offers company sales and transportation service to diverse customers over its service territory.

Historically, Northwest Natural purchases about two-thirds of its annual gas supply from Canada. CanWest has been exporting gas to Northwest Natural since January 1989 under short-term authorizations at an average contract load factor of approximately 69 percent. CanWest exported 660 10^6m^3 (23.3 Bcf) in 1989-90 and 453 10^6m^3 (16.0 Bcf) in 1990-91. Over the 1982-90 period, Northwest Natural's total market demand and number of customers have grown at annual rates of 5.2 percent and 3.7 percent respectively. Although Northwest Natural anticipates lower total demand growth in the future, it expects its core market to experience a higher rate of growth due to:

- the current low saturation rate among residential customers;
- the price of gas being significantly cheaper than alternate energy sources;
- environmental concerns among the public; and,
- increased gas demand for cogeneration.

Northwest Natural has produced a sales forecast for a 20-year period beginning in 1991 and estimated a two percent average rate of growth in total sales for the first ten years.

The forecast projects no growth in industrial demand and anticipates that the conversion of industrial customers from company sales to transportation service will stabilize at the present level. The projected core market demand would be approximately 85 percent of the total annual demand in the first five years, which is similar to Northwest Natural's past experience.

Northwest Natural stated that the average load factor for the export over the contract term would be approximately 70 percent. The export would represent approximately 34 percent of Northwest Natural's total annual supply.

2.3.2 Transportation

CanWest signed a firm service ("FS") agreement, renewable on a yearly basis, with Westcoast on 19 April 1991. Northwest Natural has an existing transportation service agreement with Northwest expiring in 2013. No new facilities are required for the export.

CanWest is responsible for demand charges on Westcoast but is reimbursed for these charges by Northwest Natural under the terms of the gas sales contract.

2.3.3 Gas Sales Contract

Northwest Natural and CanWest executed a gas sales contract, as amended, dated 1 January 1989. The contract term began 1 January 1989 and ends 1 November 2003. The contract provides for a Daily Contract Quantity ("DCQ") of 2 606 10^3m^3 (92.0 MMcf).

Under the contract, Northwest Natural can nominate up to the DCQ. The contract stipulates a minimum take quantity of 53 percent of the DCQ and includes a make-up provision for deficiency volumes of gas paid for but not taken by Northwest Natural.

The contract price is comprised of a demand charge and a commodity charge. The demand charge is the Westcoast demand toll as set in the Westcoast FS Toll Schedule. The commodity charge has been contractually set at $U.S. 1.28/GJ ($U.S. 1.35/MMBtu) for system gas and $U.S. 0.85/GJ ($U.S. 0.90/MMBtu) for storage gas until 1993/1994. The commodity charge is to be competitively priced relative to the price of competing energy sources and gas supplies in Northwest Natural's market area and comparable to netback prices received by producers supplying CanWest under similar terms and conditions. The contract provides for price renegotiation on or before 1 August of each contract year. Unresolved price disputes are settled through arbitration.

The estimated price that would have been in effect under the terms of this contract at the British Columbia border as of 1 January 1992 was $2.09/GJ ($2.20 MMBtu).

2.3.4 Regulatory Status

CanWest received a removal permit from the British Columbia Ministry of Energy, Mines and Petroleum Resources ("EMPR") on 3 December 1991 for a 12-year term with a term volume of 11.3 10^9m^3 (400 Bcf). CanWest obtained a finding of producer support from the British Columbia Petroleum Corporation ("BCPC") dated 24 September 1991.

Northwest Natural obtained an import authorization from the U.S. Department of Energy, Office of Fossil Energy ("DOE/FE") on 18 May 1990 for a term ending 1 November 2003.

2.4 Views of the Board

The Board's estimate of reserves exceeds the total commitments of CanWest's supply pool. As well, the Board's projection of productive capacity indicates that CanWest can meet its requirements throughout the proposed term. The Board is therefore satisfied with the adequacy of CanWest's gas supply.

The Board notes that transportation arrangements have been secured on all required pipelines. Further, the Board is satisfied that all fixed transportation costs in Canada associated with the export would be recovered.

The Board is satisfied that the market supports the export and notes that exports have already been occurring under short-term authorizations. In the Board's view, the contractual provisions regarding deficiency volumes, demand charges and minimum gas take assure reasonable take levels under the gas sales contract. The Board notes that the contract price can be reviewed

annually to respond to market changes and therefore finds that the contract will likely be durable for the applied-for term.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

The Board notes that all regulatory authorizations are in place. Producer support was demonstrated by a finding of producer support issued to CanWest.

Regarding the requested licence term, the Board notes that the gas sales contract expires on 1 November 2003 whereas the applied-for licence would not terminate until the fall of 2004. The Board is not persuaded to recommend the issuance of a licence beyond the end of the contract term.

2.5 Decision

The Board has decided to issue a gas export licence to CanWest, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1994 unless exports have commenced under the licence on or before 1 November 1994, in which case the term will end on 1 November 2003.

Chapter 3

Enserch Development Corporation, on behalf of Encogen Northwest, L.P.

3.1 Application Summary

By application dated 29 November 1991, Encogen sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	For a period of 15 years following the later of 1 April 1993 or the date of first deliveries.	
Point of Export	-	near Huntingdon, British Columbia	
Maximum Daily Quantity	-	271.8 10^3m^3	(9.6 MMcf)
Maximum Annual Quantity	-	99.1 10^6m^3	(3.5 Bcf)
Maximum Term Quantity	-	1 441 10^6m^3	(50.9 Bcf)
Tolerance	-	10 percent per day and 2 percent per year	

The gas proposed for export would be produced from pools contracted to CanWest in British Columbia. The gas would be transported on the Westcoast system for delivery at the international border near Huntingdon, British Columbia. The gas would then be shipped in the U.S. for final delivery to the cogeneration facility, to be located in Bellingham, Washington. The electrical output from the facility would be sold to Puget Sound Power & Light Company ("Puget") while the thermal energy would be sold to Georgia-Pacific Corporation ("Georgia-Pacific").

3.2 Gas Supply

Encogen has executed a 15-year gas sales contract with CanWest that may be extended on a yearly basis. The gas will be provided to Encogen from CanWest's corporate supply pool in British Columbia. Accordingly, no reserves are specifically dedicated to the performance of the gas sales contract. A discussion of CanWest's gas supply is provided in Section 2.2 of these Reasons.

3.3 Market, Commercial Arrangements and Regulatory Status

3.3.1 Market

The gas proposed for export would be part of the supply used to fuel a 160 MW natural gas-fired cogeneration facility. The cogeneration facility would be located on property purchased from Georgia-Pacific. Georgia-Pacific, the thermal energy purchaser, will utilize the steam and warm

water in its pulp and paper and chemical plant. Puget, the power purchaser, will purchase a target 18,978 GW.h of energy from the cogeneration facility over the 15-year term of the power purchase agreement. The target purchase quantity approximates with an average 90 percent capacity factor of the cogeneration facility for the term of the power purchase agreement.

The facility has been certified as a QF under the applicable U.S. legislation. It will utilize natural gas as its primary fuel and fuel oil as its emergency back-up.

Construction of the plant has commenced using interim short-term financing. The applicant expected non-recourse project financing to be finalized in May 1992. The applicant stated that receipt of an export licence before substantial spending has occurred would assist in concluding financing at an early date. The cogeneration facility is expected to be available for commercial generation on 1 July 1993.

3.3.2 Transportation

CanWest executed an agreement, dated 19 April 1991, as amended, for firm service on Westcoast for the applied-for licence term and volume. No new facilities would be required on Westcoast to accommodate the proposed export.

Pursuant to the Natural Gas Services Agreement dated 1 April 1991, as amended, between Encogen and Development Associates Inc. ("DA"), DA will purchase the gas from Encogen at Sumas, Washington. DA is then required to provide firm transportation for the gas on Northwest and deliver the gas to the Cascade Natural Gas Corporation ("Cascade") inlet. Encogen would then repurchase the gas, less shrinkage, from DA. DA is also required to provide certain fuel management, administrative and other services under the agreement. Encogen stated that this arrangement was necessary as, at the time transportation for the project was being arranged, firm transportation for the required volume was not directly available on Northwest. It was therefore necessary to contract with a third party, DA, holding such rights.

Northwest requires additional facilities to accommodate 73.7 10^3m^3 (2.6 MMcfd) of the 271.8 10^3m^3 (9.6 MMcfd) proposed for export. The U.S. Federal Energy Regulatory Commission ("FERC") has already approved these facilities, subject to finalization of an environmental impact statement. This statement was expected in April 1992.

Transportation service on Cascade for the applied-for licence term and volume is provided under an agreement dated 14 November 1991 between Cascade and Encogen. An application was filed on 27 November 1991 with the Washington Utilities and Transportation Commission ("WUTC") for approval of the facilities required to accommodate the service to Encogen. A decision was expected in the spring of 1992 and the facilities were expected to be in place by the projected commercial operation date of the plant.[1]

3.3.3 Gas Sales Contract

CanWest and Encogen executed a gas sales contract dated 16 October 1991 for the sale of up to 8 835 GJ (9,300 MMBtu) per day. The primary term of the contract is for 15 years from the

1. By letter dated 7 October 1992, Encogen advised the Board that the environmental impact statement was issued in April 1992, that the final order was issued by FERC on 5 June 1992 and that construction of the Northwest facilities was proceeding on schedule. As well, Encogen advised that WUTC approved the Cascade facilities on 30 April 1992 and that construction of these facilities was scheduled to commence on 1 November 1992.

start-up date of the plant. The term continues on a yearly basis thereafter until terminated by either party. The contract is subject to the receipt of non-recourse financing for the project and a plant start-up date of no later than 31 October 1993. Encogen takes delivery of the gas at the interconnection of the Westcoast and Northwest systems near Huntingdon, British Columbia.

The price of gas delivered prior to the earlier of 1 October 1993 or the start-up date is determined by negotiation. The price of gas delivered in the first year following the earlier of 1 October 1993 or the start-up date is fixed at $U.S. 1.75/GJ ($U.S. 1.84/MMBtu). The price is then escalated by five percent in each year of the contract term.

Encogen is required to nominate a minimum annual volume equivalent to the product of a daily delivered volume of approximately 7 950 GJ (8,370 MMBtu) and the number of days in which the plant was not scheduled for maintenance during the year. Should Encogen nominate less than this amount in a year, then it is obligated to pay a gas inventory charge ("GIC") equal to the product of the deficient volume times 30 percent of the price otherwise payable under the contract. Encogen is also required to pay the GIC if deliveries have not commenced under the contract by 1 October 1993.

Encogen estimated that the contract price that would have occurred at the British Columbia border under the terms of this contract as at 1 January 1992 would have been $2.01/GJ ($2.12/MMBtu).

3.3.4 Power Purchase Agreement

The proposed sale of electricity would be pursuant to the agreement dated 26 September 1990, as amended, between Georgia-Pacific and Puget. The power contract continues for a period of 15 years from the start of the operating period and has been approved by the WUTC.

The cogeneration facility is a base load facility, requiring Puget to purchase the facility's total net electrical output. The purchase price is a fixed annual negotiated rate. If, at the end of the operating period, the purchase target exceeds the energy actually delivered, then the purchase price for such deliveries shall be 67.5 mills/kW.h adjusted to the consumer price index. Puget may curtail purchases from the facility during May and June in each year of the operating period when increased hydraulic generation is available resulting from the annual spring run-off and discharge of water to aid the migration of salmon. The curtailment of purchases requires the mutual agreement of the parties and the steam host must remain unaffected by the curtailment. So long as the thermal energy transfer to Georgia-Pacific is not interrupted, the project's QF status is unaffected. The project is of a three-turbine design, and at least two turbines must operate to generate the maximum steam delivery obligations.

Puget may direct Encogen to cure any breach or default. If Encogen does not do so, Puget may recover any resultant expenses from Encogen. Puget has the option to purchase the facility for one dollar within 120 days of the expiration of the operating period.

3.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy would be pursuant to the steam sales agreement, dated 18 July 1991, between Georgia-Pacific and Encogen. The thermal agreement continues for 15 years from the commercial operation date. If the power agreement is extended, then the thermal agreement is extended for a like term. Georgia-Pacific is obligated to purchase sufficient quantities of warm water and steam to enable the cogeneration facility to maintain its QF status. Georgia-Pacific is penalized if the thermal take is below minimum QF requirements. If Encogen

defaults on the contract it is required to pay Georgia-Pacific $U.S. 1 million for each year remaining in the contract.

Encogen is required to make steam available, on a 12-month rolling average, at 99 percent of the time for the first 150,000 lbs./hour and at 97 percent of the time for steam in excess of 150,000 lbs./hour. Warm water will be provided at no charge. For steam requirements exceeding the maximum annual contractual quantity, Georgia-Pacific will pay the actual cost to provide the steam. Such costs would include the cogeneration facility's lost revenues for failure to provide electricity to Puget.

3.3.6 Regulatory Status

On 9 December 1991, CanWest applied to the EMPR for a long-term Energy Removal Certificate. A decision was expected on the application in the summer of 1992. The finding of producer support for the CanWest/Encogen contract was issued by the BCPC on 20 November 1991.

Encogen applied for its DOE/FE import authorization on 23 December 1991. A decision was expected on its application in the summer of 1992. As discussed in section 3.3.2, federal and state authorizations for additional pipeline facilities in the U.S. were expected in the spring of 1992. The plant has QF certification.[1]

3.4 Views of the Board

As discussed in section 2.2 of these Reasons, the Board's estimate of CanWest's reserves exceeds the total commitments of CanWest's supply pool. As well, the Board's projection of productive capacity indicates that CanWest can meet its requirements throughout the proposed term. The Board is therefore satisfied with the adequacy of CanWest's gas supply.

The Board is satisfied that the CanWest/Encogen contractual arrangements were negotiated at arm's length. The Board notes that the contract price does not specifically contain a demand charge component but is satisfied that the full fixed cost of transportation on Westcoast's system would be recovered through the contract price and the GIC.

The contract contains a fixed annual price escalator of five percent. The Board considers that this would likely permit adjustment to reflect changing market conditions given that the project has direct contractual links between its other commercial arrangements and the gas sales contract.

The Board is of the view that the GIC would ensure a high rate of take. Encogen estimated that the load factor would be approximately 95 percent. The Board feels that this estimate is reasonable.

A finding of producer support was issued by the BCPC on 20 November 1991.

Regarding the outstanding regulatory authorizations, the Board is of the view that the applications are well advanced and does not foresee difficulties in this regard.

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1. By letter dated 7 October 1992, Encogen advised the Board that it expected to receive its energy removal certificate and DOE/FE import authorization in the fall of 1992.

3.5 Decision

The Board has decided to issue a gas export licence to Encogen, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 April 1993 or the date of first deliveries, and shall end on 1 November 1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end 15 years following the commencement of the term of the licence.

Chapter 4

Kamine Natural Dam Cogen Co., Inc.

4.1 Application Summary

By application dated 30 December 1991, Kamine sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	1 November 1993 to 31 October 2008	
Point of Export	-	near Iroquois, Ontario	
Maximum Daily Quantity	-	340 10^3m^3	(12 MMcf)[1]
Maximum Annual Quantity	-	117.8 10^6m^3	(4.2 Bcf)
Maximum Term Quantity	-	1 767 10^6m^3	(62.4 Bcf)
Tolerance	-	10 percent per day	
	-	Any volumes authorized for export which are not actually exported during any year may be exported during the remaining term of the licence[2]	

The gas for the proposed export would be produced from pools in Alberta and Saskatchewan controlled or contractually dedicated to North Canadian Marketing Inc. ("NCM") and its parent, North Canadian Oil Limited ("NCO"). The gas would be transported on the NOVA Corporation of Alberta ("NOVA") system for delivery to the TransCanada system near Empress, Alberta. Gas from Saskatchewan would be delivered at TransCanada/TransGas Limited ("TransGas") interconnections.

The gas would be shipped by TransCanada to the international border near Iroquois, Ontario. The gas would then flow on the Iroquois Gas Transmission System, L.P. ("IGTS") and St. Lawrence Gas Company Inc. ("St. Lawrence Gas") systems for final delivery to Kamine's proposed cogeneration facility.

The facility will be situated at the site of the James River Paper Company, Inc. ("James River") paper mill in Natural Dam, New York. Electricity and steam generated at the facility would be sold to Niagara Mohawk Power Corporation ("Niagara") and James River, respectively.

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1. By letter dated 11 September 1992, Kamine requested that the applied-for daily volume in its application be increased to 348.4 10^3m^3 (12.3 MMcf). This increase was requested for fuel gas downstream of the delivery point.

2. Kamine withdrew its request for this tolerance by letter dated 14 April 1992.

Table 4-1

Comparison of Estimates of Kamine's Established Gas Reserves With the Applied-for Term Volume

$10^6 m^3$ (Bcf)

Kamine[1]	NEB[2]	Applied-for Volume
8 643 (305.2)	7 819 (276.2)	1 767 (62.4)

1. As of 1 November 1993.
2. As of 31 December 1990. The Board's estimate of remaining reserves would be at least 616 $10^6 m^3$ (21.7 Bcf) less than shown if further adjusted for estimated production from 1 January 1991 to 1 November 1993. The Board's estimate of reserves would then be 17 percent less than Kamine's, but still four times larger than the applied-for volume.

4.2 Gas Supply

4.2.1 Supply Contracts

Kamine has executed a 15-year natural gas purchase agreement with NCM for 340 $10^3 m^3/d$ (12 MMcfd). The gas supply for the proposed export will be provided from NCM's corporate supply pool. Accordingly, no specific pools have been contractually dedicated to the sales. Under the provisions of the agreement, NCM warrants to deliver the gas nominated by Kamine. In the event NCM is unable to deliver the gas, it will indemnify Kamine against all incremental costs of obtaining replacement fuel. In addition, NCM's parent company, NCO, has guaranteed certain of the obligations and liabilities of NCM under the gas purchase agreement.

NCM's corporate supply pool consists of its own reserves and gas it has contracted from seven producers. These contracts constitute approximately 65 percent of NCM's submitted supply.

4.2.2 Reserves

Table 4-1 shows that the Board's estimate of Kamine's contracted remaining gas reserves is ten percent lower than Kamine's estimate, but is more than four times higher than the applied-for volume.

Kamine submitted estimates of reserves from producers supplying gas to the project from Alberta and Saskatchewan. Kamine's estimates of reserves include both proven and probable reserves.

Three of the producers submitted probable reserves, which account for less than two percent of Kamine's total supply.

The Board's estimate of Kamine's reserves includes both proven and probable reserves; probable reserves account for one percent of the Board's estimate.

The discrepancy between Kamine's and the Board's estimate of reserves can be attributed to differences in the interpretation of rate studies, in estimates of area, net pay, porosity, gas saturation and recovery factors, and in the interpretation of working interest.

In its analysis of Kamine's gas supply, the Board recognized 130 pools in Alberta and 41 pools in Saskatchewan; only 28 of the 171 pools are currently on production. Alberta pools comprise 64 percent of the total reserves, while Saskatchewan pools account for the remainder. Most of the pools contain less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas, 35 pools contain reserves of 100 10^6m^3 (3.5 Bcf) to 1 000 10^6m^3 (35 Bcf) and only six pools contain reserves greater than 1 000 10^6m^3 (35 Bcf). These six largest pools are found in Cretaceous sand deposits.

There were 18 pools for which the Board's and the producers' estimates varied by more than 20 10^6m^3 (0.7 Bcf). The two pools with the largest differences in estimates are discussed in more detail below.

Estimates for NCO's Medicine Lodge Viking A pool in Alberta account for 37 percent of the reserves difference. NCO based its estimate on a P/Z analysis. The Board believes that using a P/Z plot at this time is premature since less than ten percent of the pool's estimated reserves have been produced. Therefore the Board has calculated a volumetric estimate of reserves for this pool.

Furthermore, the Board does not agree with NCO's working interest calculation. NCO's submitted land holdings are restricted to a 50 percent interest in only one section of the Medicine Lodge Viking A pool. However, the pool has been mapped by both NCO and the Board to cover a minimum of 14 sections on an areal distribution and therefore NCO's land would correspond to a 3.6 percent working interest. NCO calculated that its well would get the largest share of the reserves because it assumed that there would be no additional wells drilled in this pool and that all future production would come from the three currently producing wells. The Board believes that either new wells or new completions would undermine NCO's assumption. Accordingly, the Board assigned NCO only ten percent of the pool's reserves based on expected drainage of adjacent undrilled areas.

The difference in estimates for NCO's Knopcik Halfway pool in Alberta account for 24 percent of the total discrepancy. Differences relate to estimates of area, porosity, recovery factor and the Board's assignment of some reserves as probable. The difference in area is related to NCO's net pay contouring. The Board determined a lower average porosity and assigned a lower recovery factor than used by NCO. The Board also considered the mapped reserves south of section 36-72-11W6M as probable since there are currently no wells capable of production in that area.

In summary, the Board's estimate of reserves is less than Kamine's but greatly exceeds the applied-for volume. Differences in estimates of reserves are due to differences in interpretation of rate studies, reservoir parameters and the determination of net working interest. The Board also acknowledges that NCO has provided a corporate warranty in the application.

4.2.3 Productive Capacity

Figure 4-1 compares the Board's and Kamine's projections of productive capacity with the applied-for volumes. Kamine intends to obtain its own supply for fuel gas but, under the provisions of the sales contract, Kamine may obtain fuel gas from NCM if Kamine has nominated less than the Maximum Daily Quantity ("MDQ").

Both the Board's and Kamine's assessments of productive capacity indicate adequate gas supply throughout the proposed export term. The Board adjusted its productive capacity projection to reflect production at the applied-for annual rate. This accounts for the Board's projection being relatively flat compared to Kamine's projection, which gradually declines throughout the proposed export term. Kamine's higher productive capacity estimate at the outset of the term is attributable to its higher estimate of reserves.

4.3 Market, Commercial Arrangements and Regulatory Status

4.3.1 Market

The gas proposed for export would be used to fuel a 58 MW gas-fired combined-cycle cogeneration facility. The facility is currently under construction and scheduled for completion in June 1993. James River, the steam purchaser, is a marketer and manufacturer of consumer products, food and consumer packaging, and consumer related communication papers. Niagara, the power purchaser, is a New York public utility with extensive experience with cogeneration projects.

The cogeneration facility has received QF status from the FERC and is considered a QF pursuant to New York State public service law Section 2.2-a. Financing for the project was in place at the time of the hearing.

The plant will utilize natural gas as its primary fuel and number 2 fuel oil as back-up. The facility is expected to operate at an average 92 percent capacity over the life of the investment.

4.3.2 Transportation

Kamine has signed precedent or firm agreements with TransCanada, IGTS and St. Lawrence Gas for periods ranging from 15 years to 25 years. New facilities required for this export are included in TransCanada's 1993/94 facilities application and St. Lawrence Gas' 1993 construction plan.

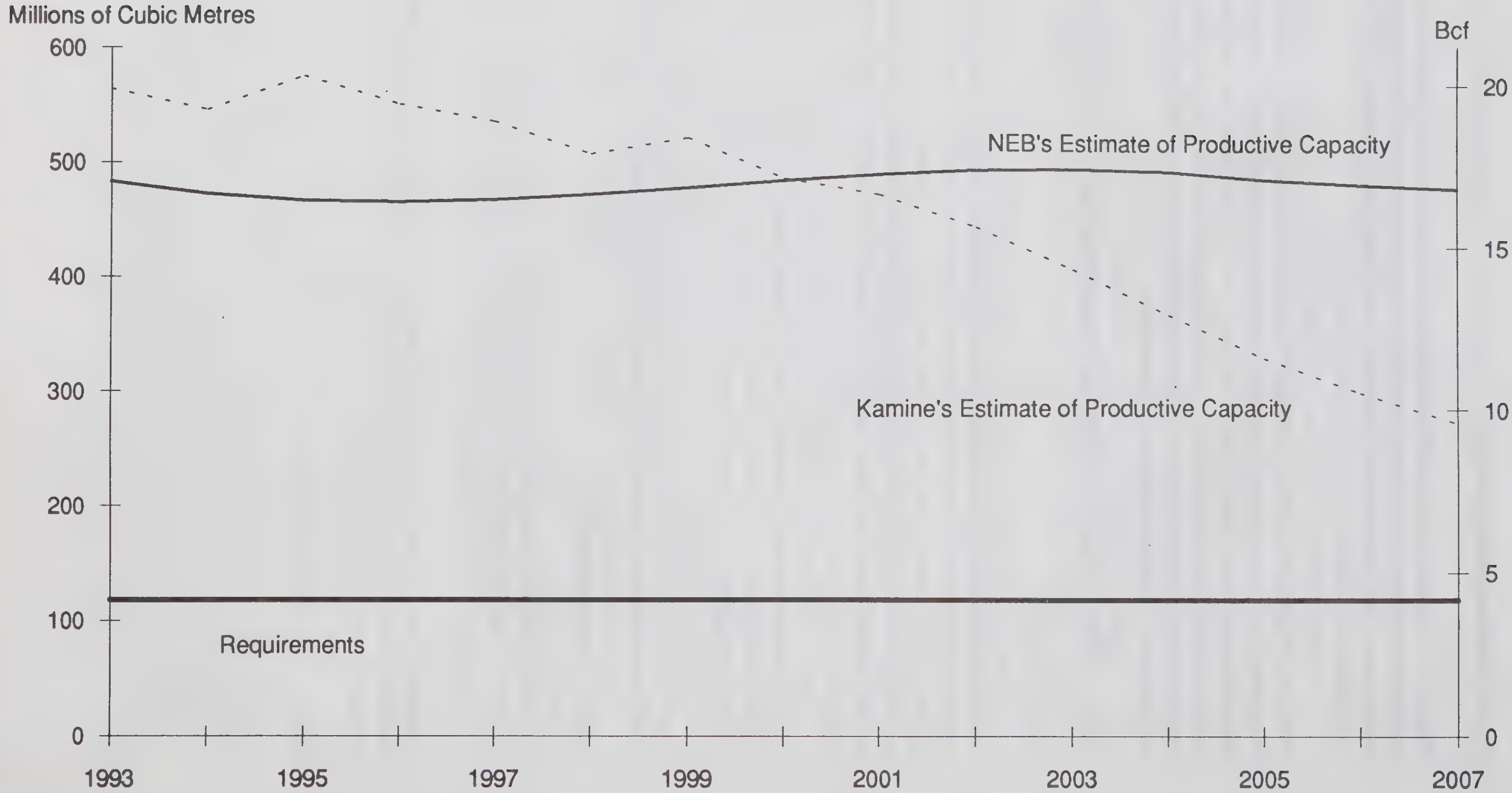
Kamine is directly responsible for all transportation charges on TransCanada. NCM is responsible for charges on NOVA and TransGas but recovers these charges through the gas sales contract.

4.3.3 Gas Sales Contract

NCM and Kamine executed a gas sales contract dated 30 July 1991. The contract term begins 1 November 1993 and ends 1 November 2008. The contract provides for an MDQ of 289 10^3m^3 (10.2 MMcf) and an Incremental Daily Volume ("IDV") of 51 10^3m^3 (1.8 MMcf). The contract is subject to the completion of necessary transportation and financial arrangements and the receipt of regulatory approvals by 1 November 1993. Kamine stated that the contract was negotiated at arm's length. There is no provision for renegotiation of the contract.

Figure 4-1

Comparison of Kamine's & NEB's Estimates of Annual Productive Capacity



Kamine is required to take 80 percent of the MDQ in order to avoid paying the GIC. The GIC is set at $U.S. 0.38/GJ ($U.S. 0.40/MMBtu) and is applied to the difference between actual nominations and the required gas take. After 1994, the GIC would be increased by the annual percentage increase in the producer price index for the U.S. northeast. Kamine is also required to purchase the total gas requirements of the facility from NCM.

The MDQ can be reduced by mutual agreement after 1 November 1994. The contract also provides for third party sales, such as Kamine's peak-shaving agreement with The Consumers' Gas Company Ltd., to maximize Kamine's load factor on TransCanada.

The price is comprised of a commodity charge and a demand charge. For sales up to the MDQ, the commodity charge is fixed at $U.S. 1.48/GJ ($U.S. 1.56/MMBtu) in 1992 and increases to $U.S. 5.26/GJ ($U.S. 5.54/MMBtu) in 2008. For IDV sales, the price would be $U.S. 1.26/GJ ($U.S. 1.33/MMBtu) in 1993 and adjusted thereafter by a factor based on Niagara's service rate schedule. Kamine stated that the commodity price schedule reflects the parties' reasonable assessment of future gas market conditions compatible with long-term electricity sales and prices to Niagara.

The demand charge is 120 percent of the monthly NOVA demand charge, regardless of actual volumes taken, multiplied by a factor. The numerator of this factor is the difference between the monthly contract volume and the sum of volumes actually delivered, nominated but not delivered and relieved from NOVA demand charges. The denominator is the monthly contract volume.

The estimated price for sales up to the MDQ that would have been in effect under the terms of this contract at the delivery point as of 1 January 1992 was $1.70/GJ ($1.80 MMBtu). For IDV sales, the price was $1.53/GJ ($1.61 MMBtu).

4.3.4 Power Purchase Agreement

The proposed sale of electricity from the cogeneration facility would be pursuant to the power purchase agreement, dated 4 December 1987, as amended, between Kamine and Niagara. This contract continues for a period of 25 years from the initial operation date with automatic one-year renewals thereafter until terminated by either party. The New York Public Service Commission ("NYPSC") has approved the power agreement and two subsequent amendments. A third amendment to the power agreement has been filed with the NYPSC. However, the NYPSC no longer approves specific amendments. Rather, concerns with specific amendments will now be raised in the course of prudency reviews, in the same way any utility decision can be reviewed.

Niagara will accept delivery of all the electricity produced by the plant where the cogeneration facility's transmission line meets Niagara's 115 kV transmission system. The price of the electricity reflects purchases during three periods. The price during the first period will be 6¢/kW.h, while the price during the second and third periods will be equal to 95 and 90 percent of Niagara's avoided cost, as approved by the NYPSC. If the NYPSC should no longer approve the avoided cost calculation, then the projected avoided costs would be determined pursuant to the power contract. Contract costs include projected avoided production, capacity and transmission costs. Projected avoided costs would incorporate transmission losses.

Should the facility lose its PURPA QF status, Niagara would continue to purchase electricity, but at a price of 85 percent of its avoided costs.

Niagara is not required to purchase if the cost to do so would be greater than that which it would incur if it did not purchase from the cogeneration facility. However, before Niagara can curtail it must make a presentation to the NYPSC that such operational circumstances will occur. Niagara must then receive written NYPSC approval before it may curtail purchases. If Niagara does not comply with NYPSC requirements, then it is required to pay Kamine as if no curtailment had occurred.

4.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy from the cogeneration facility would be pursuant to the energy services agreement dated 29 November 1991 between Kamine and James River. The agreement will continue for a term of 25 years from the initial operation date, and may be extended for two five-year periods. The agreement filed with the application was a redacted version because the applicant was of the opinion that publication of the commercial terms, including price, may prejudice it in negotiations with steam hosts for other projects.

The contract requires the steam host to take the minimum annual thermal energy volume to ensure the maintenance of the facility's PURPA QF status. James River Corporation, the parent company of James River, has guaranteed the obligations of James River under the energy services agreement to take the minimum annual thermal energy volume. In the event of a default by James River, the James River Corporation will perform or cause to perform the required obligations.

4.3.6 Regulatory Status

NCM applied for removal permits from the Alberta Energy Resources Conservation Board ("ERCB") and Saskatchewan Energy and Mines on 28 February 1992 for a term commensurate with that applied-for hereunder. Decisions on the applications are pending.

Regarding U.S. federal authorizations, FERC granted QF status to the proposed facility on 29 August 1991. Kamine anticipates a decision on its DOE import authorization by October 1992.

The only outstanding State approval is from the NYPSC for pipeline facilities connecting the facility to Niagara. Kamine anticipates a decision shortly.[1]

4.4 Views of the Board

Both the Board's and Kamine's estimates of reserves exceed the applied-for requirements. Similarly, projections of productive capacity by both the Board and Kamine indicate no potential gas supply deficiencies. The Board is therefore satisfied with the adequacy of Kamine's gas supply.

The Board notes that transportation has been arranged on all required existing and proposed pipelines. Further, the Board is satisfied that all fixed transportation costs in Canada associated with the export would be recovered.

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1. By letter dated 13 October 1992, Kamine advised the Board that decisions on the applications for removal permits and for DOE/FE import authorization were expected in the fall of 1992. NYPSC approval of the required pipeline facilities was granted on 9 July 1992.

The Board is satisfied that the markets support the proposed export. The Board notes that the power purchaser, Niagara, has experienced an increase in demand for electricity in its service territory in recent years. As well, the facility has received its QF status.

In the Board's view, the contractual provisions regarding deficiency volume payments, demand charges and NCM's position as the exclusive gas supplier for the facility ensure adequate take levels under the sales contract. The Board notes that the contract contains a fixed price schedule for the whole term but considers the contract durable in light of the assured markets.

The Board has reviewed the gas contract and notes that it has been negotiated at arm's length.

The Board notes that the provincial removal permits, DOE/FE import authorization and NYPSC's approval of the proposed St. Lawrence Gas' pipeline are pending. The Board recognizes that these applications are well advanced and does not foresee difficulties in this regard.

Producer support was demonstrated by the gas contract executed between NCM and Kamine.

4.5 Decision

The Board has decided to issue a gas export licence to Kamine, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1993, and shall end on 1 November 1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end on 31 October 2008.

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & ATCOR Ltd.

5.1 Application Summary

By application dated 23 October 1991, Selkirk and ATCOR applied for a joint natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee Gas Pipeline Company ("Tennessee"), for a term of 15 years plus the period from commencement of deliveries to the next following first day of November.	
Point of Export	-	near Iroquois, Ontario	
Maximum Daily Quantity	-	479 10^3m^3	(17 MMcf)
Maximum Annual Quantity	-	176 10^6m^3	(6.21 Bcf)
Maximum Term Quantity	-	2 712 10^6m^3	(95.75 Bcf)
Tolerances	-	Ten percent per day and two percent per year	

The gas proposed for export would be produced mainly in Alberta from existing company reserves and from reserves under contract with other producers. Some gas would also be provided from Saskatchewan. PanCanadian and ERC would also be suppliers to the cogeneration facility.

The gas would be transported in Canada on NOVA and TransCanada to the international border near Iroquois, Ontario. In the U.S., IGTS and Tennessee would ship the gas to the cogeneration facility at Selkirk, New York.

The subject cogeneration facility, ("Selkirk II"), would represent a major expansion of the plant currently under construction, ("Selkirk I"), for which a gas export licence was issued following the GH-5-89 hearing. The electricity from Selkirk II would be sold to Consolidated Edison of New York, Inc. ("Con Ed"), with wheeling provided under an agreement with Niagara. The steam would be purchased by the General Electric Company ("GE") Plastics Division.

Table 5-1

Comparison of Estimates of ATCOR's Established Gas Reserves With the Applied-for Term Volume

10^6m^3 (Bcf)

ATCOR[1]	NEB[2]	Applied-for[3] Volume
12 248 (432)	11 128 (394)	2 712 (96)

1. As of 1 June 1991.
2. As of 31 December 1990.
3. ATCOR's market requirements total 11 240.9 10^6m^3 (397 Bcf).

5.2 Gas Supply

5.2.1 Supply Contracts

Selkirk executed a 15-year gas sales contract with ATCOR for 479 $10^3m^3/d$ (17 MMcfd). The gas supply for the proposed export will be provided from ATCOR's supply pool, and as such, no specific pools have been contractually dedicated to the sale. Under the provisions of the contract, ATCOR warrants to deliver the gas nominated by Selkirk. In the event that ATCOR is unable to deliver the gas, it will indemnify Selkirk against all incremental costs incurred in obtaining replacement fuel.

ATCOR has also executed gas purchase contracts of various terms with nine producers. These contracts constitute approximately 55 percent of ATCOR's supply pool.

5.2.2 Reserves

Table 5-1 shows that the Board's estimate of ATCOR's reserves is approximately nine percent lower than ATCOR's estimate and is approximately equal to ATCOR's total requirements of 11 240.9 10^6m^3 (397 Bcf), including its applied-for volume. Estimates of reserves submitted by ATCOR were prepared by McDaniels and Associates for ATCOR and the other nine producers except for Shaman Energy Corporation, which prepared its own estimate of reserves. Working interest percentages were provided so that net remaining reserves could be determined for all pools.

The discrepancy between ATCOR's and the Board's estimate of reserves arises primarily from variations in estimates for several large gas pools. The greatest divergence in estimates is within ATCOR's own supply, in particular the Herronton Turner Valley pools and the Caroline Beaverhill Lake A pools.

ATCOR's estimate of reserves for Herronton is considerably higher than the Board's due to different interpretations of net pay and gas saturation. Another factor was ATCOR's estimate of probable reserves for Herronton. While the Board did not assign probable reserves to all pools, it believes that its assessment of proven reserves is plausible. Further, the Board was unable to consider some well data in its assessment due to the confidentiality of the data. The variation in estimates of reserves for Herronton account for over 35 percent of the overall difference.

Another 14 percent of the overall difference in estimates of reserves is in the Caroline estimate. The majority of this variation is due to the larger pool area assigned by ATCOR compared to the area used by the Board. This is largely due to variations in interpretation of mapping.

The difference in estimates of reserves for the Duncan McMurray F pool, part of the reserves provided by Logan Resources Ltd., accounts for an additional 14 percent of the overall difference. The primary reason for this discrepancy is that ATCOR's estimate is based on volumetric studies for each well, while the Board's estimate is based on a P/Z production decline analysis for the whole pool. There is a slight variation in estimates of reserves for each of the remaining producers.

ATCOR and its producers also included an estimate of probable reserves for many of the pools, adding about 1 000 10^6m^3 (35 Bcf) to ATCOR's proven reserves (approximately 10 percent of the total). Most of the Board's estimates of reserves are for proven reserves, but it recognizes that some appreciation may occur.

The remainder of the difference arises primarily from the cumulative effect of small discrepancies in various reservoir parameters, including pool area and porosity. Net pay and recovery factors contribute to a lesser degree to the differences.

ATCOR's gas supply is contained in 441 pools, almost all of which are in Alberta. These pools are distributed throughout the province, mostly in Lower Cretaceous formations in east central Alberta and Devonian horizons in the foothills. Sixty-five percent of ATCOR's pools have initial marketable reserves less than 100 10^6m^3 (3.5 Bcf). Forty-eight percent of the net remaining reserves are found in 20 pools with initial marketable reserves larger than 3 000 10^6m^3 (106 Bcf).

In summary, the Board's estimate of reserves is slightly lower than ATCOR's estimate, primarily due to differences in a few large pools. However, the Board's estimate of reserves is similar to the total market requirements.

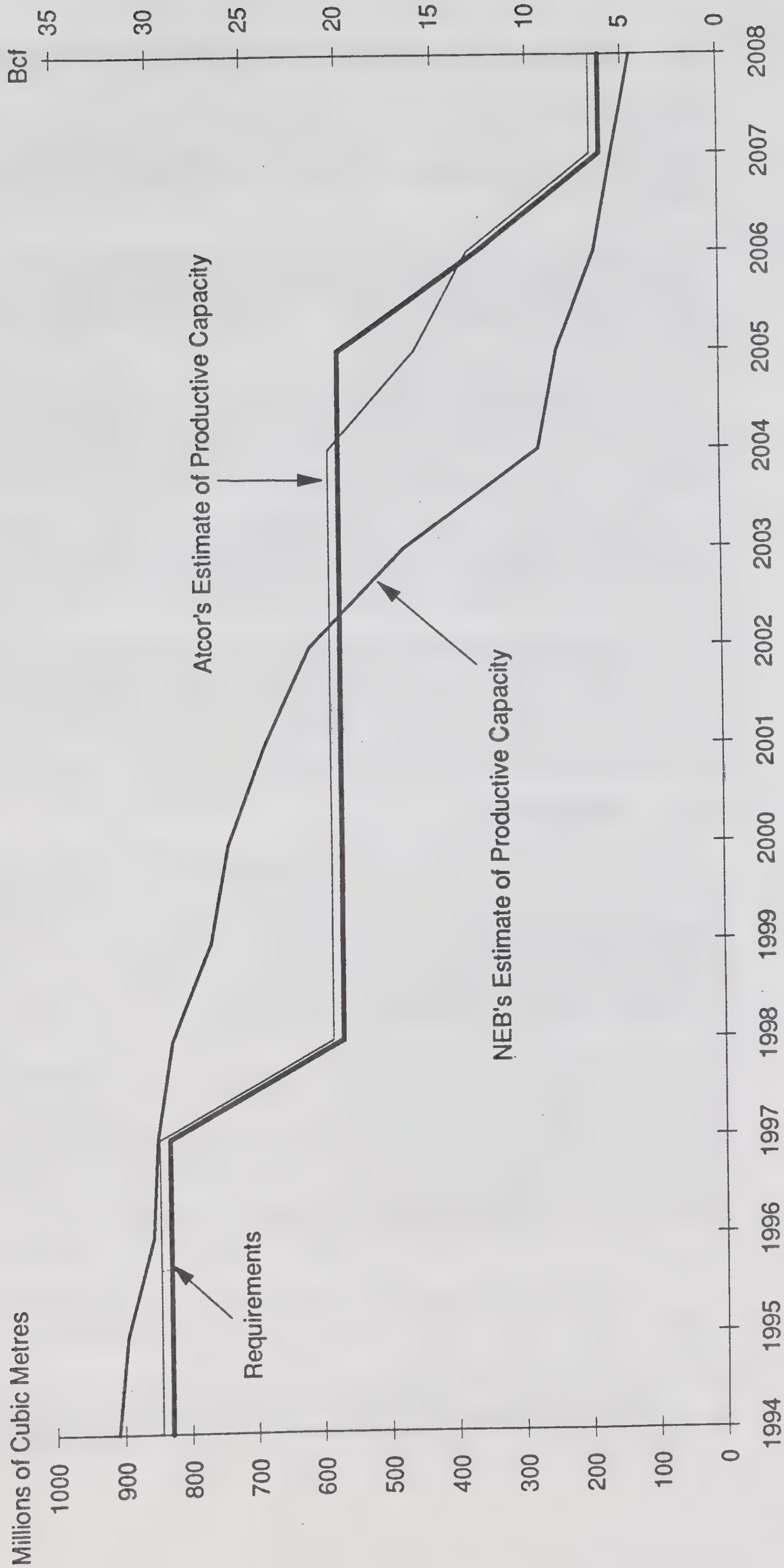
5.2.3 Productive Capacity

A comparison of the Board's and ATCOR's projection of productive capacity with ATCOR's total requirements is shown in Figure 5-1.

ATCOR's analysis indicated that it could meet its requirements throughout the proposed export term, except for a minor shortfall in 2006. The Board's analysis indicates shortfalls in productive capacity from 2003 to the end of the proposed export term. ATCOR stated that any shortfall in productive capacity could be remedied by developing or contracting for additional gas supplies.

Figure 5-1

Comparison of Atcor's & NEB's Estimates of Annual Productive Capacity



5.3 Market, Commercial Arrangements and Regulatory Status

5.3.1 Market

Selkirk would own and operate the cogeneration facility, a 277 MW combined-cycle facility to be located at the GE plant.

The gas proposed for export by ATCOR and by PanCanadian and ERC, would be used to fuel the Selkirk II operation. The Selkirk II plant would be located adjacent to and be integrated with the Selkirk I plant. The integrated operation would have a total generating capacity of about 357 MW.

At the time of the hearing, Selkirk was discussing project financing with Chase Manhattan Bank, which was also the lender to Selkirk I. It was expected that these negotiations would be finalized during the summer of 1992 and that construction of the plant would commence before 30 September 1992. Commercial operation was anticipated by June 1994.[1]

The facility would use natural gas as its primary fuel but could use low sulphur, No. 2 distillate as a back-up fuel. The gas from ATCOR, PanCanadian and ERC would represent virtually all of the firm, long-term gas supplies for the plant.

As with Selkirk I, Selkirk retained Energy Management Associates, Inc. ("EMA") to review the dispatch provisions of the contract with Con Ed. EMA used a methodology known as PROMOD III to simulate the New York Power Pool ("NYPP"). Based on its analysis, EMA concluded that Selkirk II would be dispatched as part of the NYPP base load and would generally operate at a capacity factor of approximately 90 percent.

5.3.2 Transportation

ATCOR concluded a precedent agreement with NOVA dated 1 November 1991 for firm, long-term transportation service to deliver the proposed export volumes to Empress. Selkirk executed a precedent agreement with TransCanada dated 5 March 1992. Under the terms of the gas purchase agreement, ATCOR has agreed to post a letter of credit on behalf of Selkirk to meet the financial assurances requirements of TransCanada. Selkirk is responsible for reimbursing ATCOR for the costs of obtaining and maintaining the letter of credit.

In the U.S., Selkirk executed a precedent agreement with IGTS dated 12 August 1991. The IGTS system would require expansion to existing facilities. On 14 August 1991, Selkirk executed a precedent agreement with Tennessee. Tennessee also would require expansion to its system. From the Tennessee outlet, the gas would be delivered to the cogeneration facility by a 3.4 kilometre (2.1 mile) pipeline owned and operated by Selkirk. This pipeline was previously approved by the NYPSC and has already been constructed.[2]

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1. Subsequent to the close of the hearing, Selkirk advised the Board that financial closing was expected during the fall of 1992.

2. Selkirk also advised the Board that an application for the required facilities on Tennessee was expected to be made in October 1992.

5.3.3 Gas Sales Contract

Selkirk executed a gas sales contract with ATCOR on 13 August 1991. The contract term extends for 15 years plus the period from commencement of deliveries to the next following first day of November. Subject to regulatory approvals, the term can be extended for an additional five years. Deliveries are expected to commence 1 June 1994.

The contract provides for the daily delivery of up to 479 10^3m^3 (17 MMcf) of gas at Empress or such other point mutually agreed to by the parties. The Minimum Annual Quantity ("MAQ") in any contract year is defined as 75 percent of the sum of the MDQs. Volumes up to the MAQ are termed "Tier 1" while quantities in excess of the MAQ are termed "Tier 2". If Selkirk does not take the MAQ in any contract year, the deficient volumes may be made up in the subsequent two contract years. If they are not, ATCOR has the right to reduce the MDQ on 60 days notice. Similarly, if ATCOR fails to deliver at least 97 percent of the daily nominations during a winter season, Selkirk has the option to reduce the MDQ.

Under the terms of the agreement, Selkirk may nominate, on any day, up to the MDQ at the Tier 2 commodity charge.[1] If, in any contract year, Selkirk does not nominate the full Tier 1 volumes but has purchased Tier 2 quantities, Selkirk will pay ATCOR the difference between the Tier 1 and Tier 2 commodity charges on the Tier 2 volumes received up to the MAQ.

The contract includes a two-part pricing structure, comprised of a demand charge and a commodity charge. The monthly demand charge component consists of the following two elements:

- the product of the MDQ averaged over the month and the monthly per unit demand rate paid by ATCOR for deliveries by NOVA to Empress in that month, and

- a fixed monthly charge equal to the product of the MAQ divided by twelve and a supply reservation fee of $U.S. 0.14/GJ ($U.S. 0.15/MMBtu).

The commodity charge component will depend on the quantities delivered in any month. The commodity charge for Tier 1 volumes will be calculated from an initial price of $U.S. 1.49/GJ ($U.S. 1.60/MMBtu), less the supply reservation fee of $U.S. 0.14/GJ ($U.S. 0.15/MMBtu). This initial price will be adjusted monthly by an index designed to reflect the delivered price of major competing energy supplies in New York State. For this purpose, No. 2 fuel oil, No. 6 fuel oil and natural gas prices will be considered.

The commodity charge for Tier 2 volumes will be negotiated monthly. If an agreement cannot be reached, the Tier 2 charge will be the adjusted initial price.

Selkirk submitted that, as of 1 January 1992, the Alberta border price that would have been in effect under the terms of this contract would have been $1.83/GJ ($1.93/MMBtu).

The monthly demand charge is not subject to renegotiation. The agreement allows for renegotiation of the Tier 1 commodity charge and the method of making adjustments to it after

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1. As described below, the contract contains two levels of commodity charge; the commodity charge for Tier 1 volumes - reflecting the prices of major competing energy supplies and the commodity charge for Tier 2 volumes - representing volumes at negotiated prices.

the fifth, eighth and eleventh contract years. If renegotiation is unsuccessful, then either party may request binding arbitration. Arbitration would be used to determine a delivered price of gas comparable to the delivered price of major competing energy supplies in New York State.

5.3.4 Power Purchase Agreement

The proposed sale of electricity from the cogeneration facility would be pursuant to an agreement dated 14 April 1989, as amended, between Selkirk and Con Ed. The term of the agreement is 20 years from the date the facility commences commercial operation. Wheeling from the facility to Con Ed would take place pursuant to an agreement dated 13 December 1990 between Niagara and Selkirk.

The dispatch of the cogeneration facility would be directed by Con Ed based on economic, safety and reliability considerations. When dispatched, the facility would be operated at either full capability or half capability, as directed by Con Ed. Studies show that the facility would be dispatched at a capacity factor of approximately 90 percent. Under the agreement, the parties have waived the right to a minimum price and negotiated the price of the electricity to include monthly capacity, operation and maintenance, fuel, and electricity wheeling charges. Should the facility lose its QF certification, new rates at 90 percent of the original rates specified would come into effect.

5.3.5 Thermal Energy Sales Agreement

The proposed sale of steam would be pursuant to an agreement, dated 15 February 1990, as amended, between Selkirk and GE. The agreement continues for a period of 20 years following the commercial operation date of the facility. A base amount is priced at full avoided cost. GE is required to take the minimum steam amount required to preserve the facility's QF status. As stated in the agreement for Selkirk I, Selkirk will purchase existing GE steam facilities to produce steam as needed and will utilize GE's consumable waste to produce steam from the purchased facilities. GE's existing steam facilities were not sufficient to satisfy all of GE's thermal energy requirements.

5.3.6 Regulatory Status

On 19 December 1991, ATCOR applied to the ERCB for a removal permit. As well, ATCOR has applied to have the existing Saskatchewan removal permit of one of its producers transferred to itself effective 1 November 1992.

The Alberta Petroleum Marketing Commission ("APMC") issued a finding of producer support in January 1990.

Selkirk has applied to the FERC for PURPA QF status and to the DOE/FE for import authorization. These authorizations were expected by the summer of 1992.[1]

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1. Subsequent to the close of the hearing, Selkirk advised the Board that approval of the Saskatchewan removal permit was granted on 6 October 1992 and that decisions on its applications to the ERCB and DOE/FE were expected later in the fall of 1992. Selkirk also advised the Board that the cogeneration facility had been self-certified as a PURPA QF.

5.4 Views of the Board

The Board's estimate of reserves for ATCOR's supply pool is approximately equivalent to ATCOR's total requirements. However, the Board's projection of productive capacity indicates that deficiencies relative to requirements may occur in the latter portion of the proposed export term. The Board notes that ATCOR has provided a corporate warranty to deliver the volumes nominated by Selkirk. Thus, the Board is confident that ATCOR would alleviate any possible shortfalls in gas supply by developing or contracting additional reserves. The Board is therefore satisfied with the adequacy of ATCOR's gas supply.

The Board notes that project financing arrangements were expected to be completed in the summer of 1992 and that applications for DOE/FE import authorization and FERC QF certification have been made. The Board is of the view that these applications are well advanced and does not foresee difficulties in this regard.

The Board recognizes that transportation on all required pipelines has been arranged. As well, the Board is satisfied that all fixed costs of transportation in Canada will be recovered. In particular, the demand charge component of the natural gas purchase agreement between Selkirk and ATCOR ensures that demand charges on NOVA will be recovered. As Selkirk is the shipper on TransCanada, it will be responsible for the demand charge.

The Tier 1 commodity charge component of the export price is indexed to competitive fuel oils in New York State. The Board is thus of the view that the pricing provisions contained in the gas purchase agreement permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that is in the agreement through the inclusion of renegotiation and arbitration conditions for the Tier 1 commodity charge.

The Board notes that ATCOR and the other Canadian suppliers, PanCanadian and ERC, are the primary firm, long-term suppliers to Selkirk II. As well, the contract provides for a fixed monthly charge of $U.S. 0.14/GJ ($U.S. 0.15/MMBtu) on MAQ volumes. The Board also notes that the plant is expected to be dispatched as part of the NYPP base load. Taken together, these factors should ensure that the cogeneration facility will operate at a high load factor and provide adequate levels of take.

The Board is satisfied that the downstream markets for the electricity and steam produced by the cogeneration facility are secure and that the plant would operate at a high load factor.

The Board has reviewed the gas purchase agreement and notes that it has been negotiated at arm's length. The Board notes that ATCOR received an APMC finding of producer support under the *Natural Gas Marketing Act* in January 1990.

The Board is satisfied that the applied-for licence term is appropriate given the available gas supply and the other supporting contractual arrangements.

5.5 Decision

The Board has decided to issue a gas export licence jointly to Selkirk and ATCOR. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November

1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of the licence.

Chapter 6

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & Esso Resources Canada

6.1 Application Summary

By application dated 23 October 1991, Selkirk and ERC applied for a joint natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, for a term of 15 years plus the period from commencement of deliveries to the next following first day of November	
Point of Export	-	near Iroquois, Ontario	
Maximum Daily Quantity	-	538.2 10^3m^3	(19 MMcf)
Maximum Annual Quantity	-	196.6 10^6m^3	(6.94 Bcf)
Maximum Term Quantity	-	3 031 10^6m^3	(107 Bcf)
Tolerances	-	Ten percent per day and two percent per year	

The gas proposed for export would be produced in Alberta from existing ERC reserves and from reserves under contract with various Alberta producers. PanCanadian and ATCOR would also supply gas to Selkirk II.

The gas would be transported in Canada on NOVA and TransCanada to the international border near Iroquois, Ontario. In the U.S., IGTS and Tennessee would ship the gas to the cogeneration facility at Selkirk, New York.

The cogeneration facility, owned by Selkirk, would represent a major expansion of the plant currently under construction, for which a gas export licence was issued following the GH-5-89 hearing. The electricity from the plant expansion would be sold to Con Ed, with wheeling provided under an agreement with Niagara. The steam would be purchased by GE.

Table 6-1

Comparison of Estimates of ERC's Established Gas Reserves With the Applied-for Term Volume

10^6m^3 (Bcf)

ERC[1]	NEB[2]	Applied-for[3] Volume
32 370 (1 143)	30 400 (1 073)	3 031 (107)

1. As of 1 July 1991.
2. As of 31 December 1990.
3. This represents 16 percent of ERC's total requirements, which are 18 919 10^6m^3 (668 Bcf).

6.2 Gas Supply

6.2.1 Supply Contracts

Selkirk has executed a 15-year gas sales contract with ERC for 538 $10^3m^3/d$ (19 MMcfd). ERC will provide the gas supply for the proposed export from its corporate uncontracted supply pool in Alberta. Accordingly, no specific pools have been contractually dedicated to the sale. Under the provisions of the agreement, ERC warrants to deliver the gas nominated by Selkirk. In the event it is unable to deliver the gas, ERC will indemnify Selkirk for all incremental costs it incurs in obtaining replacement fuel.

In addition to its own gas, ERC has executed four gas supply contracts of various terms with the following six producers: Hillcrest Resources Ltd., Novalta Resources Inc., Petrorep (Canada) Ltd. and an aggregated group of Shunda Energy Corporation, Northern Development Company Limited and Wintershall Oil of Canada Ltd. These contracts constitute approximately seven percent of ERC's uncontracted supply pool.

6.2.2 Reserves

ERC submitted ERCB estimates of reserves for its own pools. In those cases where ERC did not have a 100 percent interest in a pool, appropriate ownership percentages were applied to the ERCB estimates to determine net reserves. Table 6-1 shows the Board's estimate of reserves is six percent lower than that submitted by ERC but is 61 percent higher than ERC's total requirements including the proposed export volumes.

The discrepancy in estimated reserves arises primarily from variance in the Board's and the ERCB's estimates, as submitted by ERC, for several Viking pools in northeast Alberta, the Chigwell Mannville J pool and the Bonnie Glen D-3 A pool.

The Board's estimates of reserves for the Viking pools are generally based on volumetric analysis but reflect pool performance and well drainage when applicable. The result of these analyses indicated the Viking reserves in the Redwater and Craigend fields to be lower than estimates submitted by ERC. This is due primarily to smaller estimates of recovery factor determined for the Viking zone.

The Board's estimate for Chigwell is approximately 30 percent lower than the ERCB's estimate due primarily to a smaller value assigned for net pay.

The Board reviewed the solution gas reserves for Bonnie Glen D and determined that its estimate of reserves is lower than the ERCB estimate submitted by ERC. The Board based its estimate primarily on pool performance, as opposed to volumetric analysis.

The Board recognized 982 pools, all in Alberta, in the uncontracted supply pool submitted by ERC. These pools are distributed throughout the province and include most of the significant producing zones, although most of the pools are concentrated in Cretaceous strata. The Board estimated that 66 percent of the pools contain less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas. However, 40 percent of the net remaining reserves are found in pools with initial marketable reserves larger than 3 000 10^6m^3 (106 Bcf).

In summary, the Board's estimate of ERC's uncontracted gas supply pool is approximately six percent lower than that submitted by ERC, but exceeds ERC's total requirements, including the proposed export.

6.2.3 Productive Capacity

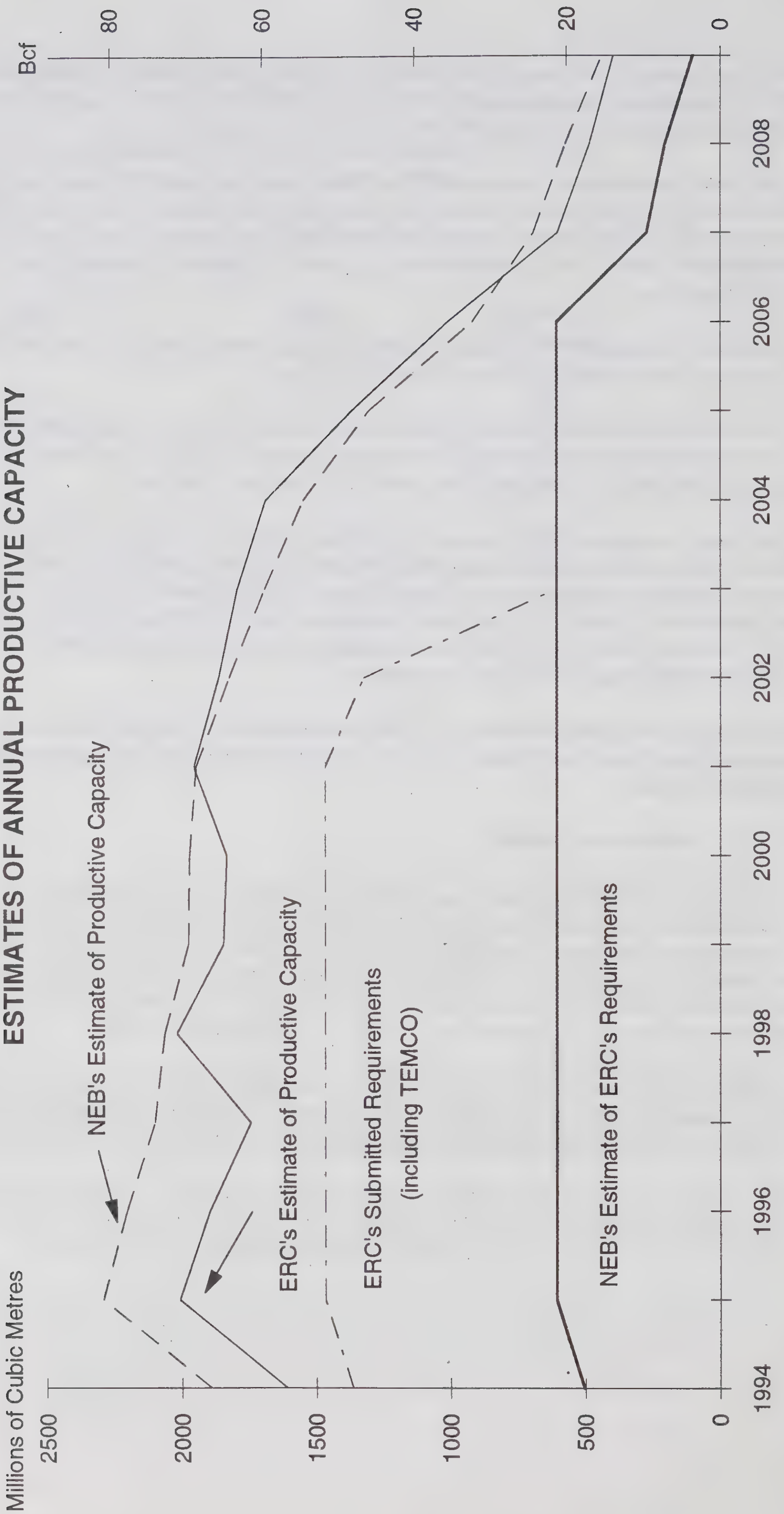
Figure 6-1 compares the Board's and ERC's projections of productive capacity with ERC's total requirements, including the applied-for volumes. Selkirk has made its own arrangements for transmission fuel gas and shrinkage on the TransCanada system and hence such volumes were excluded from the projection of ERC's productive capacity. ERC's submitted requirements included the TEMCO volumes that were transferred to CanStates Gas Marketing subsequent to the Board's decision in Volume I of the GH-1-92 Reasons for Decision.

Both the Board's and ERC's analysis indicate adequate productive capacity to meet total requirements throughout the proposed export term. Total requirements include the Selkirk II volumes and ERC's existing export licence, GL-151, which terminates in the year 2007.

ERC also provided its total corporate supply/demand balance. That balance indicates adequate gas supply throughout the projection period. ERC stated that any shortfalls in gas supply could be remedied by curtailing a portion of its own large internal requirements.

Figure 6-1

COMPARISON OF ERC'S AND NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



6.3 Market, Commercial Arrangements and Regulatory Status

6.3.1 Market

A discussion of the Selkirk II market, the Power Purchase Agreement and the Thermal Energy Sales Agreement is presented in sections 5.3.1, 5.3.4 and 5.3.5 of these Reasons respectively.

6.3.2 Transportation

ERC executed a precedent agreement with NOVA dated 1 November 1991 for firm, long-term transportation service to deliver the proposed export volumes to Empress. A discussion of the transportation arrangements downstream of Empress, Alberta is presented in section 5.3.2 of these Reasons.

6.3.3 Gas Sales Contract

Selkirk and ERC executed a gas sales contract on 12 August 1991. The initial contract term is 15 years following the first contract year. The first contract year begins with the commencement of deliveries and ends on the next following first day of November. Subject to regulatory approvals, the term can be extended for an additional five years. Deliveries are expected to commence by 1 June 1994.

The contract provides for the daily delivery of up to 538 10^3m^3 (19 MMcf) of gas at Empress. The MAQ in any contract year is defined as 75 percent of the sum of the MDQs for each day in the applicable contract year. If Selkirk does not take the MAQ in any contract year, the deficient volumes may be made up in the subsequent contract year. If they are not, ERC has the right to reduce the MDQ on 90 days notice. Similarly, if ERC fails to deliver at least 97 percent of the daily nominations during a winter season, Selkirk has the option to reduce the MDQ.

The volumes to be taken depend on the level of the commodity charge in effect in any month. In particular, the agreement contains two levels of commodity charge: Tier 1, reflecting the price of major competing energy supplies, and Tier 2, representing volumes at spot gas prices. During any month that a Tier 2 commodity charge is in effect, Selkirk is obligated to take a quantity of gas from ERC equal to at least 95 percent of ERC's pro-rated share of the total fuel used at the plant. Should Selkirk elect to purchase spot gas supplies from a third party during a month in which no Tier 2 commodity charge is in effect, then Selkirk is obligated to purchase 80 percent of its total requirements in that month from its Canadian suppliers at the Tier 1 commodity charge.

The contract includes a two-part pricing structure, comprised of a demand charge and a commodity charge. The monthly demand charge component consists of the following two elements:

- the product of the MDQ averaged over the month and the monthly per unit demand rate paid by ERC for deliveries by NOVA to Empress in that month, and
- a fixed monthly charge equal to the product of the MAQ divided by twelve and a supply reservation fee of \$U.S. 0.28/GJ (\$U.S. 0.30/MMBtu).

The commodity charge component will depend on the volumes delivered in any month. The commodity charge for Tier 1 volumes will be calculated from an initial price of \$U.S. 1.58/GJ (\$U.S. 1.70/MMBtu), less the supply reservation fee of \$U.S. 0.28/GJ (\$U.S. 0.30/MMBtu). This

initial price will be adjusted monthly by an index designed to reflect the delivered price of major competing energy supplies in New York State. For this purpose, No. 2 fuel oil, No. 6 fuel oil and natural gas prices will be considered.

The commodity charge for Tier 2 purchases will be negotiated monthly. In contrast to the provisions of the contract between Selkirk and ATCOR (see section 5.3.3), if, for any year in which it is agreed to have a Tier 2 commodity charge, Selkirk and ERC cannot reach an agreement on the level of the charge, then it will be set by a formula essentially reflecting the spot price of Canadian natural gas at Empress.

The monthly demand charge is not subject to renegotiation. The agreement allows for renegotiation of the Tier 1 commodity charge and the method of making adjustments to it, and of the supply reservation fee, at three year intervals following the first full contract year. If renegotiation is unsuccessful, then either party may request binding arbitration. Arbitration would be used to determine a delivered price of gas comparable to the delivered price of major competing energy supplies in New York State. The Tier 2 commodity charge is subject to renegotiation but not arbitration. Beginning in the first full contract year, if the parties do not agree on a methodology to determine the Tier 2 commodity charge, there will be no charge in effect.

Selkirk submitted that as of 1 January 1992, the Alberta border price that would have been in effect under the terms of this contract would have been \$1.95/GJ (\$2.06/MMBtu).

6.3.4 Regulatory Status

On 15 April 1992, ERC applied to the ERCB for a removal permit.

Selkirk has applied to the FERC for QF status and to the DOE/FE for import authorization. These authorizations were expected by the summer of 1992.[1]

6.4 Views of the Board

The Board's estimate of reserves is similar to the ERCB estimate submitted by ERC. Both estimates substantially exceed the total commitments of the supply pool. Projections of productive capacity by both the Board and ERC indicate no potential gas supply deficiencies. The Board is therefore satisfied with the adequacy of ERC's gas supply.

The Board notes that project financing arrangements were expected to be completed during the summer of 1992 and that applications for DOE/FE import authorization and FERC QF certification have been made.

The Board recognizes that transportation on all required pipelines has been arranged. As well, the Board is satisfied that all fixed costs of transportation in Canada will be recovered. In particular, the demand charge component of the gas sales contract between Selkirk and ERC ensures that demand charges on NOVA will be recovered. As Selkirk is the shipper on TransCanada, it will be responsible for the demand charge.

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1. Subsequent to the close of the hearing, ERC advised the Board that it expected a decision on its removal permit application in the fall of 1992. Selkirk has also advised the Board that a decision on its application for DOE/FE import authorization was expected in the fall of 1992 and that the cogeneration facility had been self-certified as a PURPA QF.

The Tier 1 commodity charge component of the export price is indexed to competitive fuel oils in New York State. The Board is thus of the view that the pricing provisions contained in the gas purchase agreement permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that is in the agreement through the inclusion of renegotiation and arbitration conditions for the Tier 1 commodity charge.

The Board notes that ERC and the other Canadian suppliers, PanCanadian and ATCOR, are the primary firm, long-term suppliers to Selkirk II. As well, the contract provides for a fixed monthly charge of $U.S. 0.28/GJ ($U.S. 0.30/MMBtu) on MAQ volumes. The Board is also satisfied that the downstream markets for the electricity and steam produced by the cogeneration facility are secure. In particular, the Board notes that the plant is expected to be dispatched as part of the NYPP base load. Taken together, these factors should ensure that the cogeneration facility will operate at a high load factor and provide adequate levels of take.

The Board has reviewed the gas purchase agreement and is satisfied that it has been negotiated at arm's length.

The Board is satisfied that the applied-for licence term is appropriate given the available gas supply and the supporting contractual arrangements.

As the gas proposed for export would come from reserves owned by or under contract to ERC, a demonstration of producer support was not required.

6.5 Decision

The Board has decided to issue a gas export licence jointly to Selkirk and Imperial Oil Resources. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November 1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of the licence.

Chapter 7

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited

7.1 Application Summary

By application dated 23 October 1991, Selkirk and PanCanadian applied for a joint natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, for a term of 15 years plus the period from commencement of deliveries to the next following first day of November	
Point of Export	-	near Iroquois, Ontario	
Maximum Daily Quantity	-	538.2 10^3m^3	(19 MMcf)
Maximum Annual Quantity	-	196.6 10^6m^3	(6.94 Bcf)
Maximum Term Quantity	-	3 031 10^6m^3	(107 Bcf)
Tolerances	-	Ten percent per day and two percent per year	

The gas proposed for export would be produced from PanCanadian's corporate reserve pool in Alberta. ERC and ATCOR would also supply Selkirk II.

The gas would be transported in Canada on NOVA and TransCanada, to the international border near Iroquois, Ontario. In the U.S., IGTS and Tennessee would ship the gas to the cogeneration facility at Selkirk, New York.

The cogeneration facility would represent a major expansion of the plant currently under construction, for which a gas export licence was issued following the GH-5-89 hearing. The electricity from the plant expansion would be sold to Con Ed, with wheeling provided under an agreement with Niagara. The steam would be purchased by GE.

Table 7-1

Comparison of Estimates of PanCanadian's Established Gas Reserves With the Applied-for Term Volume

10^6m^3 (Bcf)

PanCanadian[1]	NEB[2]	Applied-for[3] Volume
9 737 (343.7)	10 218 (360.7)	3 031 (107.0)

1. As of 22 May 1991.
2. As of 31 December 1990.
3. PanCanadian's existing market requirements in addition to the applied-for volume total 5 430 10^6m^3 (191.7 Bcf).

7.2 Gas Supply

7.2.1 Supply Contracts

Selkirk has executed a 15-year gas sales contract with PanCanadian for 538.2 $10^3m^3/d$ (19 MMcfd). PanCanadian will provide the gas supply from its corporate supply pool. Accordingly, no specific pools have been contractually dedicated to the sale. Under the provisions of the contract, PanCanadian warrants to deliver the gas nominated by Selkirk. In the event it is unable to deliver the gas, PanCanadian will indemnify Selkirk for all incremental costs of obtaining replacement fuel.

7.2.2 Reserves

PanCanadian submitted ERCB estimates of reserves for its pools. In cases where less than 100 percent of the pool was owned by PanCanadian, the ERCB applied appropriate ownership percentages to determine PanCanadian's net reserves. Table 7-1 shows that the Board's estimate of PanCanadian's reserves is approximately five percent higher than that submitted by PanCanadian and almost double PanCanadian's total requirements, including the proposed export volumes.

The divergence in estimates of reserves arises primarily from the cumulative effect of small differences in reservoir parameters for individual pools. The reserves submitted by PanCanadian were estimated on a section by section basis for each pool, while the reserves estimated by the Board were evaluated on a pool basis and prorated based on overall working interest.

PanCanadian's gas supply is contained in about 342 pools. These pools are distributed throughout Alberta and include many significant producing zones, the majority being Cretaceous. Most of PanCanadian's pools contain less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas (net to PanCanadian). Several of these pools are part of large multi-field pools, in which PanCanadian maintains very small land holdings. About 11 percent of the net remaining reserves are found in pools with initial marketable reserves greater than 1 000 10^6m^3 (35.3 Bcf).

In summary, the Board's estimate of reserves is similar to PanCanadian's and both estimates are approximately three times greater than the applied-for volume. The divergence in estimates of reserves arises primarily from the cumulative effect of small differences in several pools.

7.2.3 Productive Capacity

Figure 7-1 compares the Board's and PanCanadian's projections of productive capacity with PanCanadian's total requirements. PanCanadian's projection indicates adequate productive capacity except for minor shortfalls in the four years commencing in 2006. The Board's projection indicates that PanCanadian can meet its requirements throughout the proposed term. The difference in outlook is primarily attributable to the Board adjusting its projection of productive capacity to reflect expected production levels.

PanCanadian stated that any possible shortfalls in productive capacity could be offset by other existing reserves it owns or from the flexibility it has to match the development of its pools with the deliverability required by its sales contracts.

7.3 Market, Commercial Arrangements and Regulatory Status

7.3.1 Market

A discussion of the Selkirk II market, the Power Purchase Agreement and the Thermal Energy Sales Agreement is presented in sections 5.3.1, 5.3.4 and 5.3.5 of these Reasons respectively.

7.3.2 Transportation

PanCanadian concluded its precedent agreement with NOVA in January 1992. A discussion of the transportation arrangements downstream of Empress, Alberta is presented in section 5.3.2 of these Reasons.

7.3.3 Gas Sales Contract

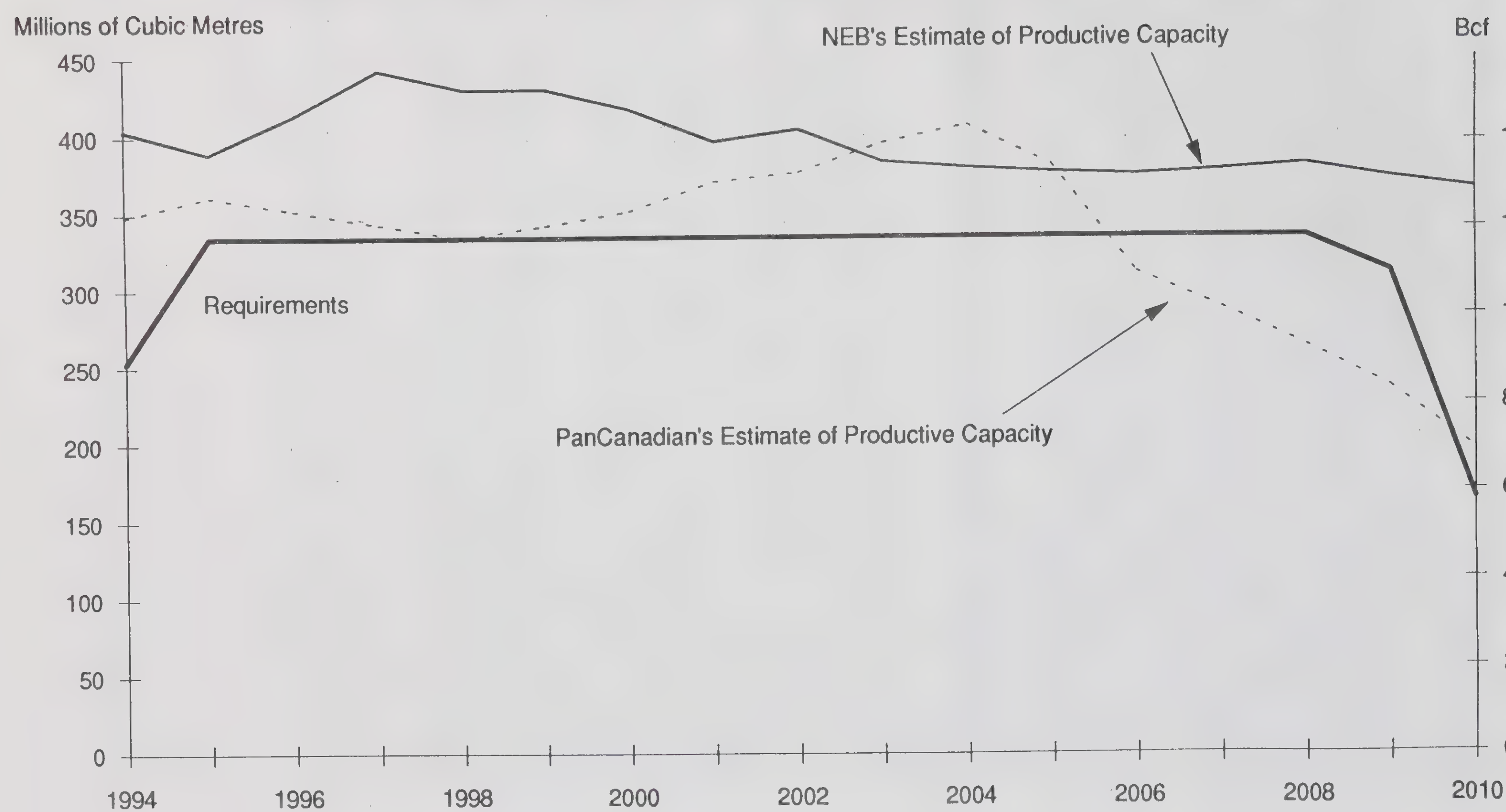
Selkirk and PanCanadian executed a gas sales contract on 12 August 1991. The contract term extends for 15 years plus the period from commencement of deliveries to the next following first day of November. Subject to regulatory approvals, the term can be extended for an additional five years. Deliveries are expected to commence by 1 June 1994.

The contract provides for the daily delivery of up to 538 10^3m^3 (19 MMcf) at Empress. The agreement defines MAQ as 75 percent of the sum of the MDQs.

Under the terms of the agreement, Selkirk may purchase up to the MDQ at the prevailing commodity charge. These sales are defined as "Contract Price volumes". In addition, Selkirk and PanCanadian will discuss, each month, the availability of gas at negotiated prices reflecting spot market conditions, which quantities are designated "Negotiated Price volumes". If an

Figure 7-1

Comparison of PanCanadian's & NEB's Estimates of Annual Productive Capacity



agreement cannot be concluded, there is no obligation for either party to sell or purchase Negotiated Price volumes.

Selkirk is permitted to nominate Negotiated Price volumes up to the MDQ on any day provided that these quantities, over the course of a contract year, do not exceed 25 percent of the sum of the MDQs. Should Selkirk nominate Contract Price volumes less than the MAQ and purchase Negotiated Price quantities in any contact year, then Selkirk will pay PanCanadian an amount equal to the difference between the commodity charge and the Negotiated Price, on the Negotiated Price volumes received, up to the MAQ. The Contract Price volumes and Negotiated Price volumes are similar to the Tier 1 and Tier 2 volumes in the gas sales contracts described in the previous two chapters of these Reasons.

If Selkirk does not nominate Contract Price volumes equal to the MAQ in any contract year, it will have two years to make up the deficient quantities. If the volumes are not made up, PanCanadian will have the right to reduce the MDQ on 60 days notice. Similarly, if PanCanadian fails to deliver at least 95 percent of the daily nominations during a contract year, Selkirk has the option to reduce the MDQ.

The contract includes a two-part pricing structure, comprised of a demand charge and a commodity charge. The monthly demand charge component consists of the following two elements:

- the product of the MDQ averaged over the month and the monthly per unit demand rate paid by PanCanadian for deliveries by NOVA to Empress in that month, and

- a fixed monthly charge equal to the product of the greater of the MAQ or the Contract Price volumes taken divided by twelve and an amount of $U.S. 0.28/GJ ($U.S. 0.30/MMBtu).

The commodity charge component will be calculated on the basis of an initial price of $U.S. 1.58 GJ ($U.S. 1.70/MMBtu), less the fixed charge of $U.S. 0.28 GJ ($U.S. 0.30/MMBtu). This initial price will be adjusted monthly by an index designed to reflect a delivered price of gas comparable to the delivered price of major competing energy supplies in New York State. For this purpose, No. 2 fuel oil, No. 6 fuel oil and natural gas prices will be considered.

The monthly demand charge is not subject to renegotiation. The agreement allows for renegotiation of the commodity charge and the method of making adjustments to it, at three year intervals following the second anniversary of the commencement of firm deliveries. If renegotiation is unsuccessful, then either party may request binding arbitration. Arbitration would be used to determine a delivered price of gas comparable to the delivered price of major competing energy supplies in New York State.

Selkirk submitted that, as of 1 January 1992, the Alberta border price that would have been in effect under the terms of this contract would have been $1.95/GJ ($2.06/MMBtu).

7.3.4 Regulatory Status

On 28 February 1992, PanCanadian applied to the ERCB for a removal permit.

Selkirk has applied to the FERC for PURPA QF status and to the DOE/FE for import authorization. These authorizations were expected during the summer of 1992.[1]

7.4 Views of the Board

The Board's estimate of reserves is similar to the ERCB estimate submitted by PanCanadian, and both estimates substantially exceed PanCanadian's total commitments. The Board's projection of productive capacity indicates no potential gas supply deficiencies. Therefore, the Board is satisfied with the adequacy of PanCanadian's gas supply.

The Board is satisfied that the downstream markets for the electricity and steam produced by the cogeneration facility are secure and that the plant would operate at a high load factor.

The Board notes that project financing arrangements were expected to be completed during the summer and applications for DOE/FE import authorization and FERC QF certification have been made.

The Board recognizes that transportation on all required pipelines has been arranged. As well, the Board is satisfied that all fixed costs of transportation in Canada will be recovered. In particular, the demand charge component of the natural gas purchase agreement between Selkirk and PanCanadian ensures that demand charges on NOVA will be recovered. As Selkirk is the shipper on TransCanada, it will be responsible for the demand charge.

The commodity charge component of the export price is indexed to competitive fuel oils in New York State. The Board is thus of the view that the pricing provisions contained in the gas purchase agreement permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that is in the agreement through the inclusion of renegotiation and arbitration conditions for the commodity charge.

The Board notes that PanCanadian and the other Canadian suppliers, ERC and ATCOR, are the primary firm, long-term suppliers to Selkirk II. As well, the contract provides for a fixed monthly charge of $U.S. 0.28/GJ ($U.S. 0.30/MMBtu) on MAQ volumes. The Board also notes that the plant is expected to be dispatched as part of the NYPP base load. Taken together, these factors should ensure that the cogeneration facility will operate at a high load factor and provide adequate levels of take.

The Board has reviewed the gas purchase agreement and noted that it has been negotiated at arm's length.

As the gas proposed for export would come from PanCanadian's corporate supply pool, a demonstration of producer support was not required.

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1. Subsequent to the close of the hearing, PanCanadian advised the Board that it expected a decision on its removal permit application in the fall of 1992. Selkirk has also advised the Board that a decision on its application for DOE/FE import authorization was expected in the fall of 1992 and that the cogeneration facility had been self-certified as a PURPA QF.

7.5 Decision

The Board has decided to issue a gas export licence jointly to Selkirk and PanCanadian. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November 1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of the licence.

Chapter 8

New York State Electric & Gas Corporation

8.1 Application Summary

By application dated 21 January 1992, NYSEG sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing upon the date of first deliveries and extending for a period of 12 years	
Point of Export	-	near Napierville, Québec, and Niagara Falls, Iroquois and Chippewa, Ontario	
Maximum Daily Quantity	-	255 10^3m^3	(9 MMcf)
Maximum Annual Quantity	-	93.1 10^6m^3	(3.3 Bcf)
Maximum Term Quantity	-	1 117 10^6m^3	(39.6 Bcf)
Tolerances	-	Ten percent per day and two percent per year	
	-	Any volumes authorized for export which are not actually exported during a year may be exported during the remainder of the licence term subject to the daily volume limitation and tolerance.	

The gas proposed for export would be produced from pools in Alberta and British Columbia contracted to ProGas Limited ("ProGas"). The gas would be transported on the NOVA system for delivery to the TransCanada inlet near Empress, Alberta. TransCanada would then ship the gas to the international border near Napierville, Québec. The gas would then flow on the proposed North Country Gas Pipeline Corporation ("North Country") system for final delivery to the Clinton County market.

8.2 Gas Supply

8.2.1 Supply Contracts

NYSEG has executed a 12-year gas sales contract with ProGas for 255 $10^3m^3/d$ (9 MMcfd). Among the provisions of the contract is a two-part supply assurance test. Firstly, ProGas is required to maintain its remaining established reserves at a level greater than its existing sales. Secondly, ProGas is required to ensure that its deliverability is adequate to support its existing sales obligations. These obligations are calculated using reasonably projected load factors on a five-year basis. In the event that the assurance test is not met, ProGas will contract for additional supplies, curtail all interruptible sales, and will be precluded from entering into any new long-term sales.

Table 8-1

Comparison of Estimates of NYSEG's Established Gas Reserves With the Applied-for Term Volume

10^6m^3 (Bcf)

NYSEG[1]	NEB[2]	Applied-for[3] Volume
112 900 (3,985)	96 818 (3,418)	1 117 (39)

1. As of 31 December 1991.
2. As of 31 December 1990. The Board's estimate of remaining reserves would be about 3 350 10^6m^3 (118 Bcf) less than shown if further adjusted for ProGas' 1991 estimated production. The Board's estimate of reserves would then be 17 percent less than ProGas' but 18 percent greater than ProGas' total requirement.
3. This represents about one percent of ProGas' total requirements, which are 79 153 10^6m^3 (2,794 Bcf).

ProGas will provide the gas for the proposed export from its contracted supply pool. This supply pool consists of approximately 600 purchase contracts with about 180 producers. ProGas recently signed contracts with 13 companies for additional gas supply in areas throughout Alberta and British Columbia. These new contracts constitute approximately 14 percent of its remaining reserves.

8.2.2 Reserves

ProGas provided an estimate of its remaining established reserves under contract that will be used to meet both its existing commitments and the proposed export to NYSEG. Table 8-1 shows that the Board's estimate of ProGas' remaining established reserves is 14 percent lower than ProGas' estimate, but is 22 percent higher than ProGas' total requirements.

Approximately 90 percent of ProGas' supply is in Alberta and the remainder is located in British Columbia. The Board's estimate of ProGas' reserves in Alberta is 84 115 10^6m^3 (2,969 Bcf) or about 17 percent less than the corresponding ProGas estimate. The difference in the two estimates originate primarily from differences in the geological and engineering assessment of reserves for specific pools. The pools with the largest variances in estimates of reserves are: Benjamin Rundle, Botha Debolt, Crossfield East Wabamun, Ferrier North Shunda, Joarcam Viking, Liege Grosmont, Little Bow Glauconitic 15-20, Pine Creek Bluesky and Wembley Halfway B. The Board's lower estimate of reserves for a number of large and medium sized pools is due in part to performance data not bearing out ProGas' estimate of reserves, which is based on volumetric analyses.

The Board's estimate of ProGas' reserves in British Columbia is 12 703 10^6m^3 (448 Bcf) or approximately 10 percent higher than the estimate provided by ProGas.

In its review of ProGas' gas supply, the Board recognized approximately 1,400 pools distributed throughout Alberta and northeastern British Columbia. These pools represent all the major producing zones in the Western Canada Sedimentary Basin, with the majority of the pools concentrated in Cretaceous strata. Approximately 33 percent of these pools are on production. Forty-five percent of ProGas' reserves are found in approximately 94 large pools each having initial established reserves exceeding 1 000 10^6m^3 (35 Bcf).

In summary, the Board's estimate of ProGas' established reserves is lower than that provided by ProGas, but exceeds ProGas' total requirements, including the proposed export.

8.2.3 Productive Capacity

Figure 8-1 compares both the Board's and ProGas' projections of productive capacity with ProGas' estimated total requirements, including fuel and shrinkage. ProGas has estimated its annual requirements based on a 90 percent load factor.

Both the Board's and ProGas' projections of productive capacity demonstrate adequate gas supply to meet requirements at a 90 percent load factor throughout the proposed export term. The Board's lower projection of productive capacity is primarily attributable to its lower estimate of reserves.

ProGas has an ongoing contracting program to replace declining pools. As well, ProGas can remedy shortfalls in deliverability with "best efforts" contracts with other aggregators and individual suppliers who are prepared to provide additional deliverability if required.

8.3 Market, Commercial Arrangements and Regulatory Status

8.3.1 Market

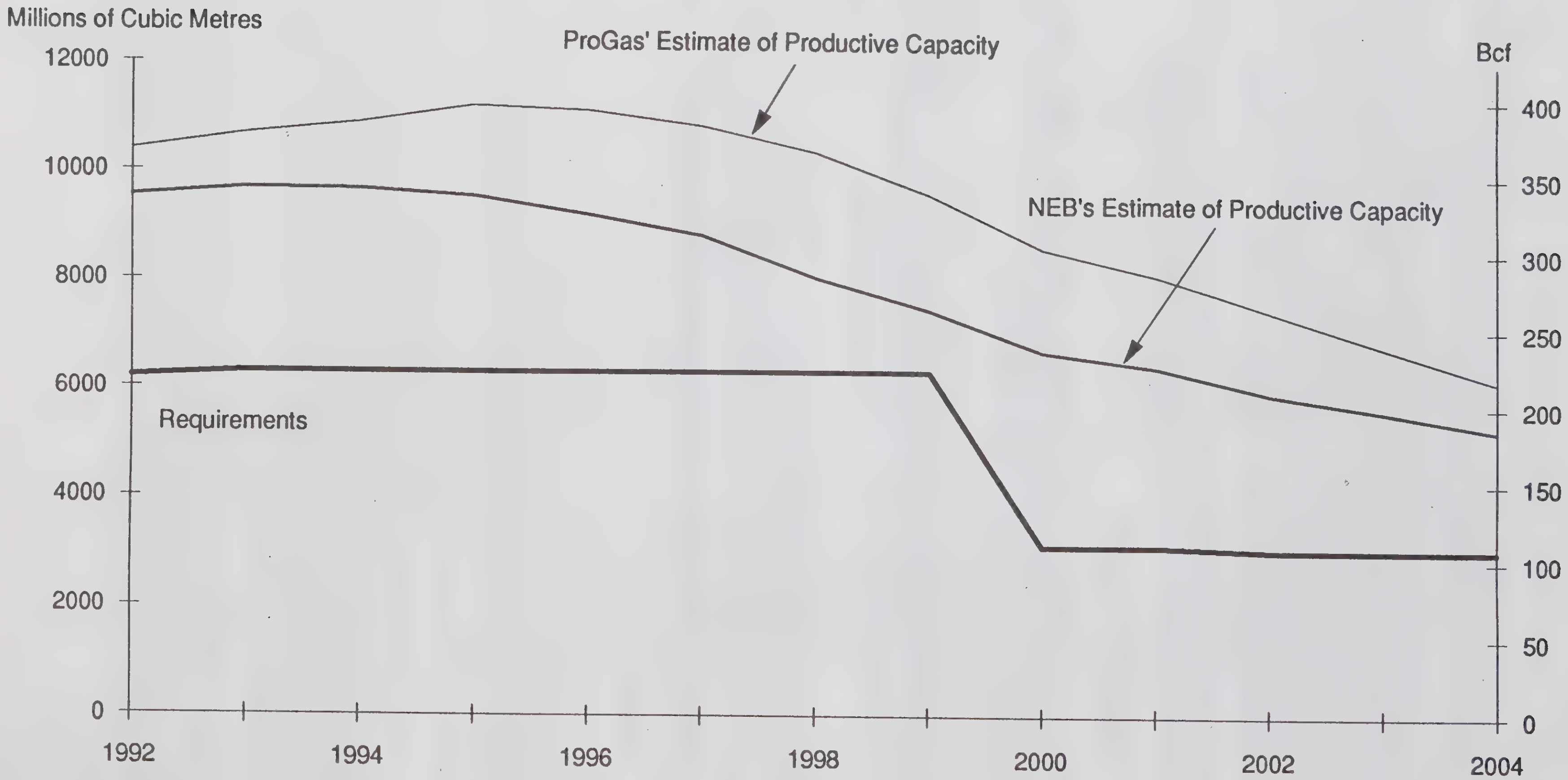
NYSEG is a regulated electric and gas utility in New York state. It serves 220,000 gas customers and has annual gas sales exceeding 1 416 10^6m^3 (50 Bcf). NYSEG proposes to develop the Clinton County market, having recently been awarded the service franchise for this area. There is no gas pipeline linking this area of approximately 85,000 people to the rest of NYSEG's service area.

Based upon market surveys of potential residential, commercial and industrial core customers, NYSEG has produced a five-year market demand forecast. NYSEG stated that this forecast was contingent on a population growth rate of 2.5 percent over the forecast period. In the first year of the forecast, industrial demand would account for approximately 92 percent of the total projected demand. By the fourth year, the percentage of total demand attributable to industrial customers is expected to decline to 81 percent.

The industrial base is comprised of six large customers. NYSEG expressed concern about the potential loss of these customers through the avoidance of NYSEG's system for the transportation of the gas to these customers ("by-pass"). NYSEG stated that any by-pass of their system would have to be authorized by the NYPSC. NYSEG stated that the threat of by-pass is not serious at present.

Figure 8-1

Comparison of NEB's & ProGas' Estimates of Annual Productive Capacity



To ensure the success of the new market, NYSEG requested three additional export points to allow gas exported under the contract to go to NYSEG's existing markets. NYSEG claimed that by spreading the cost of the new gas service onto its entire market area, the cost of service to customers in Clinton County would be comparable to that for existing markets. NYSEG stated that the additional export points were crucial to the success of the project.

The proposed North Country pipeline would deliver gas to NYSEG's core customers and a cogeneration plant in Plattsburgh, New York. NYSEG stated that the proposed pipeline would have enough capacity to meet the peak day gas requirements for the two projects. NYSEG also expressed a willingness to construct the pipeline itself should North Country decide not to build the pipeline.

NYSEG anticipated an average annual load factor in the 70 percent range over the contract term.

8.3.2 Transportation

ProGas currently holds sufficient capacity on NOVA to transport the contracted gas volume.

NYSEG has signed precedent agreements with TransCanada and North Country for 12 years and 15 years respectively for the applied-for export volume. TransCanada has included the facilities required for this export in its 1993/94 facilities application. The proposed North Country pipeline is expected to be completed by 1 November 1993.

NYSEG is directly responsible for all transportation charges on TransCanada and North Country. ProGas is responsible for transportation charges on NOVA but recovers these charges from NYSEG under the sales contract.

8.3.3 Gas Sales Contract

ProGas and NYSEG executed a gas contract dated 21 April 1992. The contract term begins with the commencement of firm deliveries and continues for 12 years. Firm deliveries are anticipated to commence between 1 November 1993 and 1 November 1994. The contract provides for an MDQ of 255 10^3m^3 (9.0 MMcf) and is subject to the completion of all contractual arrangements and receipt of all regulatory approvals by 31 December 1993. NYSEG stated that the contract was negotiated at arm's length.

NYSEG is obligated to nominate a daily quantity of gas up to the MDQ and buy gas exclusively from ProGas to serve its franchised area during the contract term. Should NYSEG nominate a volume of gas less than the MDQ for the first three contract years, then ProGas has the right to reduce the MDQ in any contract year. ProGas may also use NYSEG's unutilized transportation. NYSEG is required to take an annual average of 65 percent of the MDQ after the third contract year. The contract also includes a make-up provision for deficiency volumes of gas not taken by NYSEG.

The contractual price is comprised of NOVA demand and commodity charges, and a market-based commodity charge. The NOVA charges would be set in accordance with the ProGas cost of service and NOVA's FS tariff as determined by the APMC. The commodity charge is calculated from a fixed base price of \$1.25/GJ (\$1.32 MMBtu). This base price is escalated by an index containing the price of No. 6 fuel oil and No. 2 furnace oil, which are assigned weights of 90 percent and 10 percent respectively. There is a ten percent discount for volumes exceeding 80 percent of the MDQ.

The contract provides for renegotiation and arbitration of the price and volume provisions after the third year of the term to ensure its responsiveness to changing market conditions.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 January 1992 was \$1.77/GJ (\$1.86 MMBtu) at a 70 percent load factor.

8.3.4 Regulatory Status

NYSEG applied for a removal permit from the ERCB on 30 October 1991 for a 12-year term with a daily volume of 255 10^3m^3 (9.0 MMcf). The APMC issued a finding of producer support to ProGas on 16 October 1991.

NYSEG filed an import application with the DOE/FE on 8 April 1992 and applied to the NYPSC on 17 January 1992 for facility and service authorizations.

Approvals for the above applications were pending at the time of the hearing.[1]

8.4 Views of the Board

The Board's estimate of ProGas' established reserves exceeds ProGas' total requirements, including the proposed export, and the Board's projection of productive capacity suggests no potential deficiencies. Accordingly, the Board is satisfied with the adequacy of ProGas' gas supply.

The Board notes that transportation arrangements have been secured on all required existing and proposed pipelines. Further, the Board is satisfied that all fixed transportation costs in Canada associated with the proposed export would be recovered.

The Board has some reservations regarding the market underpinning the proposed export. The Board shares NYSEG's concern about the adverse impact of the high cost of the new service on the project's commercial viability. The Board also shares NYSEG's concern about the potential for bypass by the industrial customers once the pipeline facilities are in place. However, the Board notes that the additional export points should reduce the cost of serving the new market and assure a reasonably high load factor under the contract.

The Board has reviewed the gas contract and notes that it has been negotiated at arm's length.

In the Board's view, the contractual provisions assure adequate take levels under the gas sales contract. Specifically, the Board notes the provisions regarding deficiency volumes, payment of demand charges, exclusivity of ProGas as the gas supplier, ability of ProGas to reduce delivery obligations and to use NYSEG's unutilized transportation rights. The Board notes that the pricing provisions are responsive to market changes, and therefore considers it likely that the contract will be durable over the applied-for term.

The Board notes that the Alberta removal permit, DOE/FE import authorization and NYPSC facility and service authorizations are pending, but does not foresee any difficulty in this regard.

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1. Subsequent to the close of the hearing, NYSEG advised the Board that DOE/FE import authorization was expected in the fall of 1992. Decisions on the applications to the ERCB and NYPSC were pending at the time the Board released its decision.

Finally, the Board notes that the APMC issued a finding of producer support to ProGas on 16 October 1991.

The Board notes that NYSEG has requested a tolerance whereby any volumes authorized for export which are not actually exported during a year may be exported during the remainder of the licence term, subject to the daily volume limitation and tolerance. The Board notes that such volumes may be exported under short-term order. Further, the Board is not persuaded by the evidence presented by NYSEG that such flexibility is warranted.

8.5 Decision

The Board has decided to issue a gas export licence to NYSEG, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date of first deliveries, and shall end on 1 November 1995 unless exports have commenced under the licence on or before 1 November 1995, in which case the term will end 12 years following the commencement of the term of the licence.

Chapter 9

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-1-92 proceedings and included in this Volume.

A.B. Gilmour
Presiding Member

R.B. Horner, Q.C.
Member

R.L. Andrew, Q.C.
Member

Calgary, Canada
October 1992

Appendix I

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to CanWest Gas Supply Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 1 November 2003.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 2 606 000 cubic metres in any one day;

   (b) 952 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 11 415 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to Encogen Northwest, L.P.

1. The term of this Licence shall commence on the later of 1 April 1993 or the date of first deliveries, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 15 years following the commencement of the term of the licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 271 800 cubic metres in any one day;

(b) 99 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 1 441 300 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to Kamine Natural Dam Cogen Co., Inc.

1. The term of this Licence shall commence on 1 November 1993, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end on 31 October 2008.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 348 400 cubic metres in any one day;

   (b) 117 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 767 100 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Selkirk Cogen Partners, L.P. and ATCOR Ltd.

1. The term of this Licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) 479 000 cubic metres in any one day;

(b) 176 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 712 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Selkirk Cogen Partners, L.P. and Imperial Oil Resources

1. The term of this Licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 538 200 cubic metres in any one day;

   (b) 196 600 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 031 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Selkirk Cogen Partners, L.P. and PanCanadian Petroleum Limited

1. The term of this Licence shall commence on the later of 1 June 1994 or the date when firm transportation is available on the pipeline systems of NOVA, TransCanada, IGTS and Tennessee, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 15 years after the first day of November which follows the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 538 200 cubic metres in any one day;

   (b) 196 600 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 031 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to New York State Electric & Gas Corporation

1. The term of this Licence shall commence on the date of first deliveries, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 12 years following the commencement of the term of the licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 255 000 cubic metres in any one day;

   (b) 93 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 117 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence may be delivered to the points of export near Napierville, Québec and Niagara Falls, Iroquois and Chippewa, Ontario.